# 3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year-Old Wilmington Oil Field of Southern California

**Donald D. Clarke**
City of Long Beach
Department of Oil Properties
211 East Ocean Blvd.
Suite 500
Long Beach, California 90802

**Christopher C. Phillips**
Tidelands Oil Production Company
301 East Ocean Blvd.
Suite 300
Long Beach, California 90802

## Abstract

The giant Wilmington oil field of Los Angeles County California, on production since 1932, has produced over 2.5 billion barrels of oil from Pliocene and Miocene age basin turbidite sands. The seven productive zones were subdivided into 52 subzones through detailed reservoir characterization to better define the actual hydrologic units. The asymmetrical anticline is highly faulted and development proceeded from west to east through each of the ten fault blocks. In the western fault blocks water cuts exceed 96% and the reservoirs are near the economic limit. Several new technologies have been applied to specific areas to improve the production efficiencies and thus prolong the field life.

Tertiary and secondary recovery techniques utilizing steam have proven successful in the heavy oil reservoirs but potential subsidence has limited its application. Case history 1 involves detailed reservoir characterization and optimization of a steam flood in the Tar Zone, Fault Block II. Lessons learned were successfully applied in the Tar Zone, Fault Block V (4000 meters to the East). Case history 2 focuses on 3-D reservoir property and geological modeling to define and exploit bypassed oil. Case history 3 describes how this technology is brought deeper into the formation to capture bypassed oil with a tight radius horizontal well.

## Introduction

This paper describes three drilling projects where computerized mapping, modeling and simulation programs, used in conjunction with detailed reservoir characterization and advanced geosteering technology, have helped to successfully tap bypassed, heavy oil in California's mature supergiant the Wilmington oil field. To date, the Wilmington oil field has yielded over 2.5 billion barrels of oil of the original 9 billion barrels of oil in place. This paper focuses on how detailed reservoir characterization and 3-D visualization tools applied to horizontal drilling have improved Tidelands Oil Production Company's recovery factor in the "Old Wilmington" or western portion of the field. Background data from THUMS' Long Beach Unit (the eastern portion of the field) are included where needed to provide a thorough field overview. The methods and technologies described herein have the capability of increasing the ultimate reserves of the Wilmington oil field by hundreds of millions of barrels and will find immediate application in other mature oil fields.

## Background

The Wilmington oil field of southern California (Fig. 1), the largest oil field in the Los Angeles basin (Biddle, 1991), has produced over 2.5 billion barrels of oil (California Department of Conservation, 1999). Discovered in 1932, it produces from semi- and unconsolidated Pliocene and Miocene clastic slope and basin turbidite sandstones (Henderson, 1987; Blake, 1991). The individual reservoirs are defined by graded sequences of sandstone interlayered with siltstones and shales (Slatt et al, 1993). The entire sequence is folded and faulted (Mayuga, 1970; Clarke, 1987; Wright, 1991). Even the typically rhythmically deposited sequences have lenticular lobate


**Figure 1. Location Map showing the oil fields in the Los Angeles Basin of southern California with the Wilmington oil field highlighted in yellow.**

shapes and are complicated by basal scour, amalgamation, onlapping and channeling. The result is a sequence of rocks that often appears to be uniform, but is not. These complexities also result in permeability variations that hinder the producibility of the sandstones, impact waterflooding and result in a substantial amount of bypassed oil.

The Wilmington field has been divided stratigraphically into seven producing zones, 52 subzones, and locally into even finer sub-subzones (Henderson, 1987). A serious effort was made to establish stratigraphic continuity in as fine detail as possible. The finer subdivisions are defined as hydrologic bodies or depositional sequences. Many techniques and tools were applied to characterize the thinner sand bodies into unique units, including core description combined with log-rock typing, detailed log correlation, production/injection history matching, bypassed pay saturation analysis on recent pass-through wells, and reservoir simulation (Otott, 1996; Davies and Vessell, 1997; Davies et al, 1997). Six geologists spent the better part of one year working with thousands of old logs and assorted base maps to sort out a consistent and logical stratigraphic sequence. Besides the authors Keith Jones, Mike Henry, Linji An, Rick Strehle and David K. Davies performed a significant portion of the characterization.

We are still learning about the intricacies of Wilmington Field's reservoirs, although today's computerized visualization tools combined with advanced measurement-while drilling (MWD) have significantly contributed to the collective knowledge base about this field. Meanwhile, the field's poorly drained sands remain ideal targets for horizontal drilling.

### History of the Long Beach Unit

The Wilmington oil field is a faulted asymmetrical anticline. There are 10 larger fault blocks whose reservoirs have been managed independently. The City of Long Beach, through the Department of Oil Properties operates most of these fault blocks in the Wilmington Oil Field (Fig. 2). The Wilmington Townlot Unit (WTU), a portion of the westernmost fault block, fault block I is operated by Magness Petroleum Company. Pacific Energy Resources operates a portion of fault block II. Tidelands Oil Production Company is the field contractor for most of the

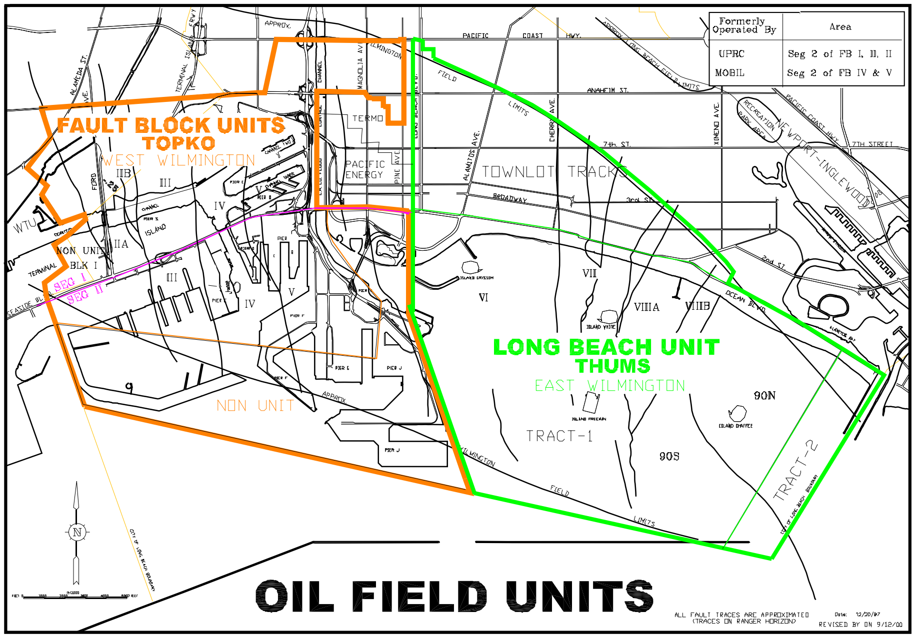


**Figure 2. Map of the Long Beach area showing the areas of the Wilmington oil field where Tidelands Oil Production Company (western portion) and THUMS Long Beach Company (Long Beach Unit) are the field contractors. The City of Long Beach, Department of Oil Properties operates both portions. The Wilmington field limits along with the Long Beach field and the Seal Beach field are shown. The coastline, harbor areas, breakwater and the oil drilling islands are shown for reference. Pacific Energy Resources operate the polygonal area between the properties. The western notch is the Wilmington Townlot Unit (WTU) and is operated by Magness Petroleum Company. Exxon operates the southeast area (not delineated) as State Lease 186 Belmont Offshore. This portion is under abandonment.**

western portion (fault blocks I-V). THUMS Long Beach Company is the field contractor for the eastern portion of Wilmington oil field (fault blocks VI-90N), which is called the Long Beach Unit (LBU). The LBU was originally produced with more than 1,000 wells drilled between 1965 and 1982 (Otott and Clarke, 1996). Even given the very long completion intervals used and water injection for pressure support, oil remained in pockets of tight thin sands, as well in areas with poor injection support. Widely ranging permeabilities and faulting caused typically viscous oil ($12.5^0$ to $16^0$ API) to be left behind in 20 to 50 ft (6 to 15 m) thick sand units.

An additional 460 wells were drilled in the Long Beach Unit from 1982 to 1986 using a “sub-zone” approach to improve sweep efficiency, which allowed another 160 million barrels (bbl) or 25.4 million cubic meters ($m^3$) to be produced. Then, after 1986 bypassed sands were selectively perforated in even finer intervals. The first horizontal well was completed in November 1993 as part of the optimized water flood project and 39 other wells have been drilled since then using a combination of computerized mapping and digitized injection surveys to identify the dominant unswept flow units, real-time analysis of MWD data to update cross sections, and geosteering supported by logging-while-drilling (LWD) data to ensure accurate wellbore placement.

Typically, the wells were placed 10 to 15 ft (3 to 5 m) below the top of the sand. Initial oil production rates from the best horizontal wells exceeded 600 bbl/ day (95.4 $m^3$/ day) and from the average wells about 300 bbl/ day (47.7 $m^3$/day), at 80% water cut, stabilizing at about 100 bbl/ day (15.9 $m^3$/day) after 300 days. Total unit oil production is 38,000 bbl/day. Blesener and Henderson (1996) describe several of the new engineering technologies that have been applied to the Long Beach Unit. These include coiled tubing drilling, drill cuttings injection and reclaimed water injection. In 1995 the LBU ran a 3-D seismic survey to help define the subsurface in greater detail (Otott et al, 1996). The survey did not provide the desired results but it did serve as a valuable tool for deep work. Several exploratory prospects were identified. One or more of these may be drilled in the next year.

THUMS was purchased from Arco by Occidental Oil and Gas Corporation in May of 2000. Occidental plans to conduct more detailed reservoir studies and possibly a new 3-D seismic survey.

**History of the "Old Wilmington" Area**

The history of the Wilmington oil field has been detailed by Mayuga, (1970); Ames, (1987); Otott and Clarke, (1996). Over 5000 wells have been conventionally drilled in the 68 years "Old Wilmington" has been on production. The entire field is on secondary recovery and oil production is down to 7000 bbl/day (1113 $m^3$/day) with an average water cut of 96.9%. Because of the steep 14% per year decline it was decided to investigate new ways to produce more oil. As part of this effort Tidelands Oil Production Company has drilled 14 horizontal wells since 1993 in four heavily drilled (3000+ wells) fault blocks (Phillips and Clarke,1998; Phillips et al, 1998). The first horizontal well project was a "Huff n' Puff" conducted in 1993 in fault block I Tar zone. Two 900-foot long horizontal wells were drilled into the $D_1$ sand. The second project was a steamflood in fault block II Tar zone. In 1995 for project two, four horizontal wells were drilled on average 1600 feet within the $D_1$ sand. A fault block IV Terminal zone waterflood well was drilled 1100 feet within the Hxb sand in 1995 as the third project. Again in 1995 five horizontal wells were drilled into the fault block V Tar zone as part of a steamflood. The wells were drilled on average 1500 feet horizontally within the $S_4$ sand. In 1997 a 1000-foot horizontal was drilled into the Hxo sand of fault block V Terminal zone to complete the fifth project.

For each project, the horizontal laterals for the waterflood wells were placed at the top of the sand to recover attic reserves. The laterals for the steamflood wells were placed at the bottom of the sand to maximize capture of oil through steam-assisted gravity drainage.

Except for the first project, 3-D modeling and visualization were used from planning through completion. To be effective, horizontal wells require precision placement. The studied areas required significant geological evaluation and characterization. The area was then modeled with software that provided 3-D visual displays of stratigraphic and structural relationships and also enabled excellent error checking of data and grids in 3-D space. The geological model was revised and modified in 3-D space. The 3-D model provided a visual reference for well planning and communicating the spatial relationships contained within the reservoir. Accurate 2-D and 3-D visualization were used for interpreting the LWD response and monitoring well progress while drilling. Map and section plots brought to the rig site allowed the drilling team to relate to the geology, thus providing a strong confidence factor. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

## Case Histories

Three case histories will be presented. Case history 1 describes a thermal enhanced recovery project that expanded on an existing steamflood project. The expansion area was subjected to detailed characterization with 3-D modeling and visualization, and the development project was completed. The technologies developed in the steamflood project were applied to the areas in fault block V and are described as case histories 2 and 3.

**Fault Block II Tar Zone Steamflood Project**

Figure 3 shows the location of the three case histories. Case history 1 is in the Tar Zone of fault block II (Fig. 4). The Tar zone of the lower Pliocene Repetto formation (Fig. 5) has been interpreted to consist of large, lobate submarine fan deposits (Redin, 1991). It is the shallowest of the major oil-producing zones in the Wilmington field and consists of interbedded siltstones, shales, and unconsolidated fine- to medium grained arkosic sands. The sand bodies were deposited as a set of compensating turbidite lobes as opposed to the sheet sands (or larger sheet lobes) that occur lower in the section. The section is actually composed of smaller sand lobes that are generally limited to less than two miles in lateral extent. The sequence is also complicated by onlap and channeling. In fault block II, the Tar zone is 250-300 ft (76-91 m) thick and occurs at depths of 2300-2800 ft (697-848 m) below sea level. The T and D sands (Fig. 5) are the best developed and most productive. Oil gravity ranges from $12^0$ to $15^0$ API, with a viscosity of 260 cp at the ambient reservoir temperature of $125^0$F ($51.7^0$C).

Fault block IIA is located in the western portion of the field between the Wilmington and the Ford faults (Fig. 3) and is down-plunge from the crest of the Wilmington structure (Fig. 5). The fault block is bounded to the west by the Wilmington fault and to the east by the Cerritos fault, both of which are permeability barriers (Fig. 3). The faults show normal displacement, with vertical offsets that range from 50 to 100 ft (15 to 30 m) but, they may have complex histories of movement. In addition, several smaller-scale faults (Ford, Ford A-1, Ford A-lB faults) exist in the northeastern portion of the block (Fig. 5). These faults exhibit vertical offset on the order of 15-30 ft (4.5-9.0 m) and are only partially sealing. The north and south limits of production are defined by oil-water contacts within the productive sands.

A Tar Zone steamflood in Fault Block II was initiated in 1982 and expanded in 1989, 1990, 1991 and 1993. In 1995, a plan was created to expand the steamflood to the south (Fig. 4). Instead of the inverted seven-spot pattern used in the earlier phases, it was decided to use horizontal

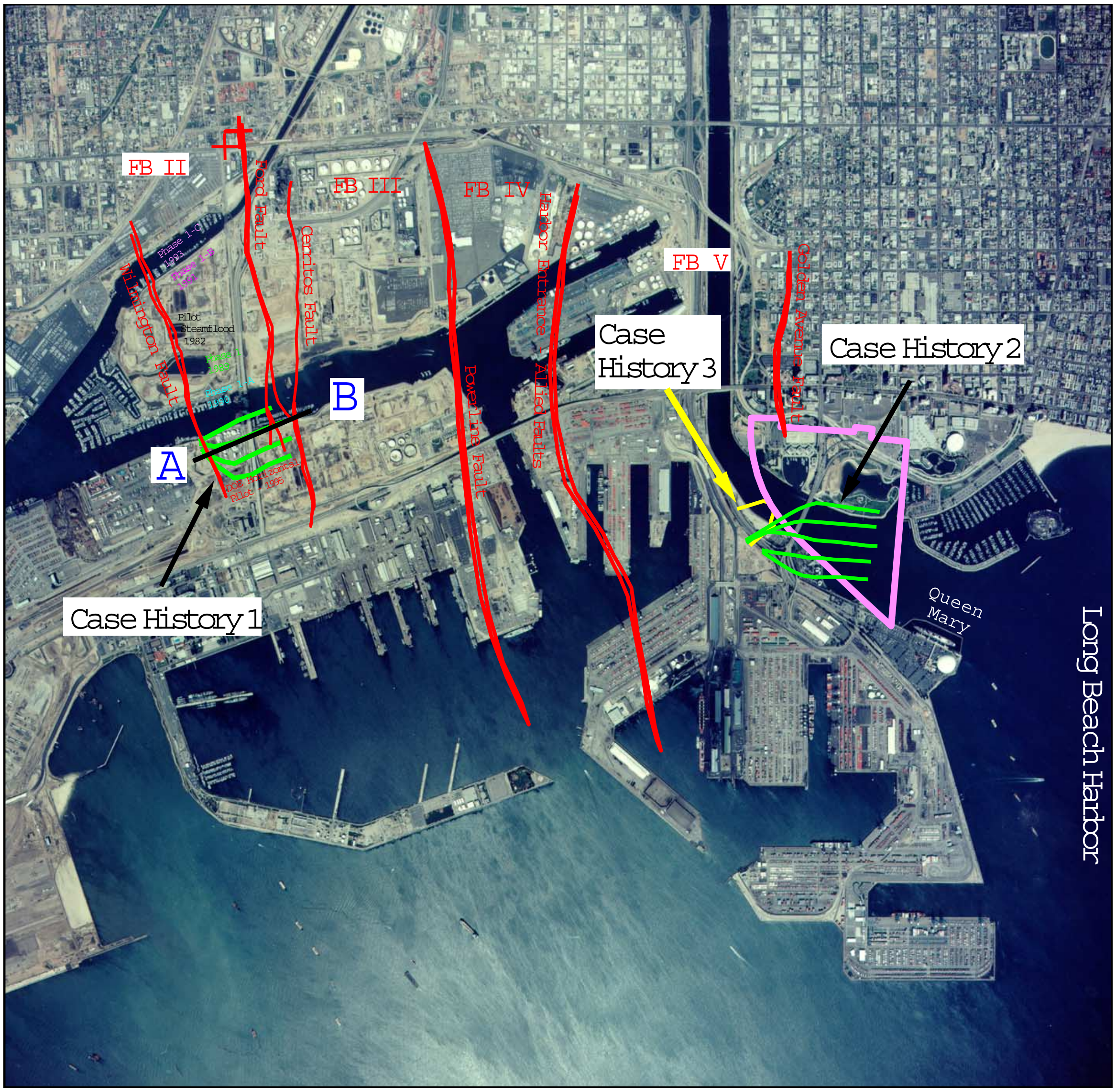


**Figure 3. Aerial photograph of Long Beach/Los Angeles Harbor showing the location of the three horizontal well projects. North is to the top. On the left (west) is the steamflood project (Case history 1) with four horizontal wells placed in the Tar zone below Terminal Island. The location of cross section AB is shown. Case history 2 consists of five horizontal wells that cross under the Los Angeles River channel and are part of a Tar zone steamflood project in fault block V. The location of cross section CD is shown. Case history 3 involves a tight radius horizontal well that lies below the case history 2 in fault block V in the upper Terminal zone. The oil activities coexist with the busiest harbor in the country and the fault block V steamflood is right below Long Beach's new $180,000,000 aquarium.**

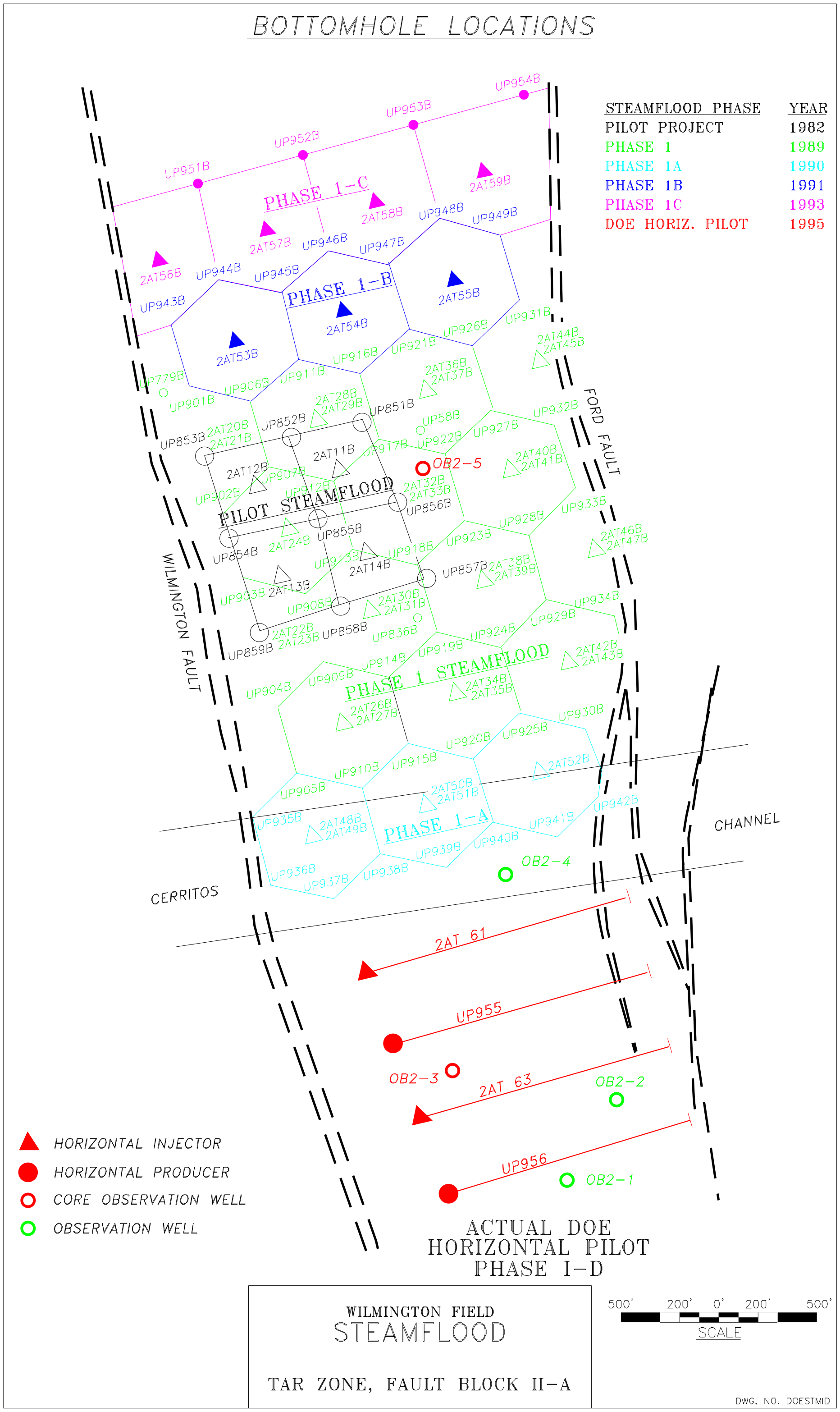


**Figure 4. Map of the fault block II area showing the location of the Wilmington oil field Tar zone, Fault Block II-A Steamflood Project. Each phase of the project is shown in color code. The here-described project focuses on the southern area where the four horizontal wells were drilled. Cross section AB goes along the well course of UP955.**

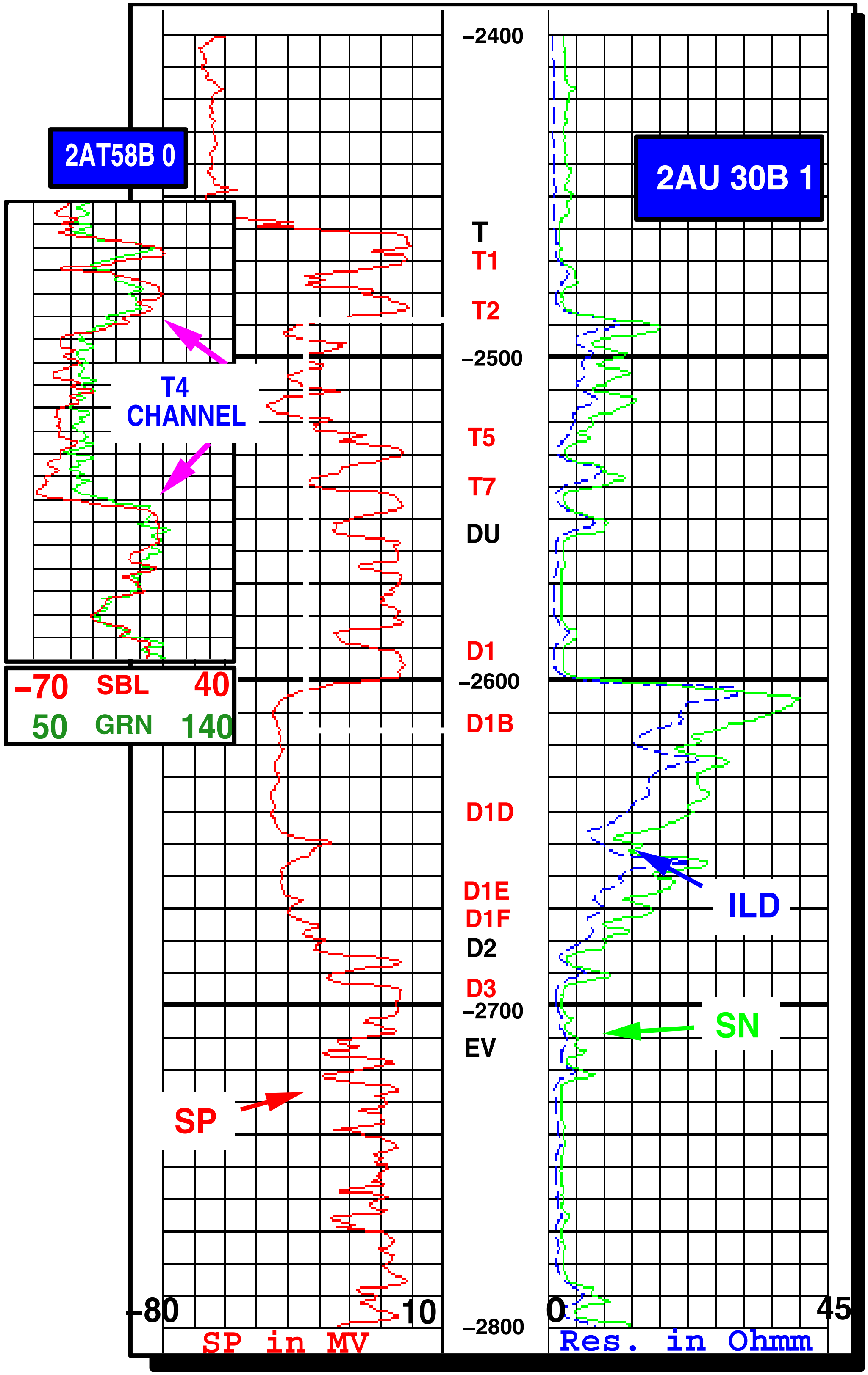


**Figure 5. Type logs for Tar zone, fault block II (Well 2AU 30B 1). The original markers are shown in black and the newly picked markers are in red. The inset showing the T4 channel is from well 2AT58B. Note the good saturation between D1 and D1E. The location for these can be seen in Figure 9.**

wells, carefully laid out so that each horizontal well would replace three to four vertical wells. Five temperature observation wells would be interspersed for monitoring the distribution of the thermal energy.

The four horizontal wells were drilled into the bottom of the 60 ft (18.3 m) thick $D_l$ sand. Two steam injectors and two producers were placed about 400 ft (122 m) horizontally apart as part of a pseudo-steam assisted, gravity drainage project. This innovative Fault Block II steamflood project received partial funding from the U.S. Department of Energy as part of a Class III Mid-Term Project (Koerner et al, 1997; United States Department of Energy,1999).

The existing maps were not detailed enough for the planned development. The only way to obtain success was to perform a detailed geologic analysis of fault block II. The well tops, coordinates and fault data was entered into a computer modeling package, and after a rough 3-D model was constructed to assess the problems, it was clear that a complete revision of the geology from scratch was necessary.

The existing six subzone intervals were further divided into 18 sub-sub zones and the faults were reevaluated. A team of geologists spent months on detailed log work to define the 18 horizons and six faults. The log data ranged from electric logs from the 1930's through complete log suites of the 1980's. Each sub-sub zone was hand mapped as to lateral extent. The faults and horizons were then three-dimensionally modeled and compared to the original interpretation.

A significant amount of the well planning was performed using this 3-D working model, which had enough detail for planning purposes. The 3-D model made visualization of the inconsistent data very easy. The data inconsistencies came from differentially subsiding horizons, caused by intraformational compaction from oil withdrawal over a 60-year period and an assortment of data entry and coordinate conversion errors. These errors were rapidly identified and corrected.

Subsidence was probably the toughest problem to solve. The intraformational compaction of the producing reservoirs varied over time and directly impacted the surface (and the distance to the producing horizons). Between 12 and 22 ft (3.7 - 6.7 m) of surface elevation was lost above the proposed horizontal lateral locations (Fig. 6). The subsidence varies, increasing from west to east toward the center of an elliptical subsidence "bowl," where the maximum subsidence to date is 29 ft (8.8 m).

To compensate for the errors, the data were adjusted for ground level change and internal compaction. These adjustments are time dependent. For example, a well drilled in 1940 could be drilled to 2,500 ft (762 m) below sea level to reach the "T" marker. The same well drilled today to the same x, y position might require drilling to 2,480 ft (768 m) below sea level to reach the "T" marker (Phillips, 1996). The ground level is lower now due to subsidence and the depths to the other markers are also different (intraformational compaction). The stratigraphic section has been compressed. Figure 7 illustrates the corrections that are applied.

After the data were modified, the mapping software facilitated the rapidly generated new geologic models by using the predefined geologic criteria. This data was quickly integrated into a more comprehensive structural model (Fig. 8). The structural model was then edited and modified where necessary. The 3-D model was recalculated many times during this iterative process. Not only was the resulting model excellent at showing the subtle differences in the geology, but it also was an invaluable tool for finding data errors.

When the acceptable 3-D deterministic model was established, cross sections along the well courses were constructed and used for geosteering (Fig. 9). The cross sections derived from the model proved to be very accurate and were used extensively. The combination of detailed sequence characterization and 3-D modeling allowed us to accurately map a previously unrecognized channel (Fig. 10) and onlap (Fig. 11).

The computerized 3-D displays greatly enhanced communication between the geologist, petroleum engineer and the driller. The geologist could rotate, slice and change the "look" of the model to improve the visualization. The geologist also displayed the offset log information on a cross section along a well course that had been scaled-up to match the real-time LWD logs. This was invaluable during drilling because the geologist was capable of accurately following the drill-bit by plotting the MWD data directly onto the computer generated cross section.

In Fault Block II the bottom of the $D_l$ sand was targeted. Instantaneous drilling rates up to 600 ft/hr (183 m/hr) were achieved because the accurate geological model helped the well site team bypass slow-drilling, problematic shales, and otherwise modify the drilling program for improved efficiency. In the end, steam-assisted, gravity-drainage horizontal wells UP-955, UP-956, 2AT-61 and 2AT-63 were successfully drilled within a 15 ft (4.5 m) target window (Fig. 12).

The steamflood project had to be terminated in January 1999 because ground elevations had dropped nearly one foot! Subsidence has been a historical problem and the continuation of activities that may cause subsidence is not permitted by the City of Long Beach. This project was marginally economic, but we feel that it was a technical success. Basically, the project started with a steam/oil ratio of 7 and by the time the steam project was shut down the steam/oil ratio was 14. More drilling would have helped greatly, but expansion was not possible at the time. In October 1999 flank wells were converted to cold-water

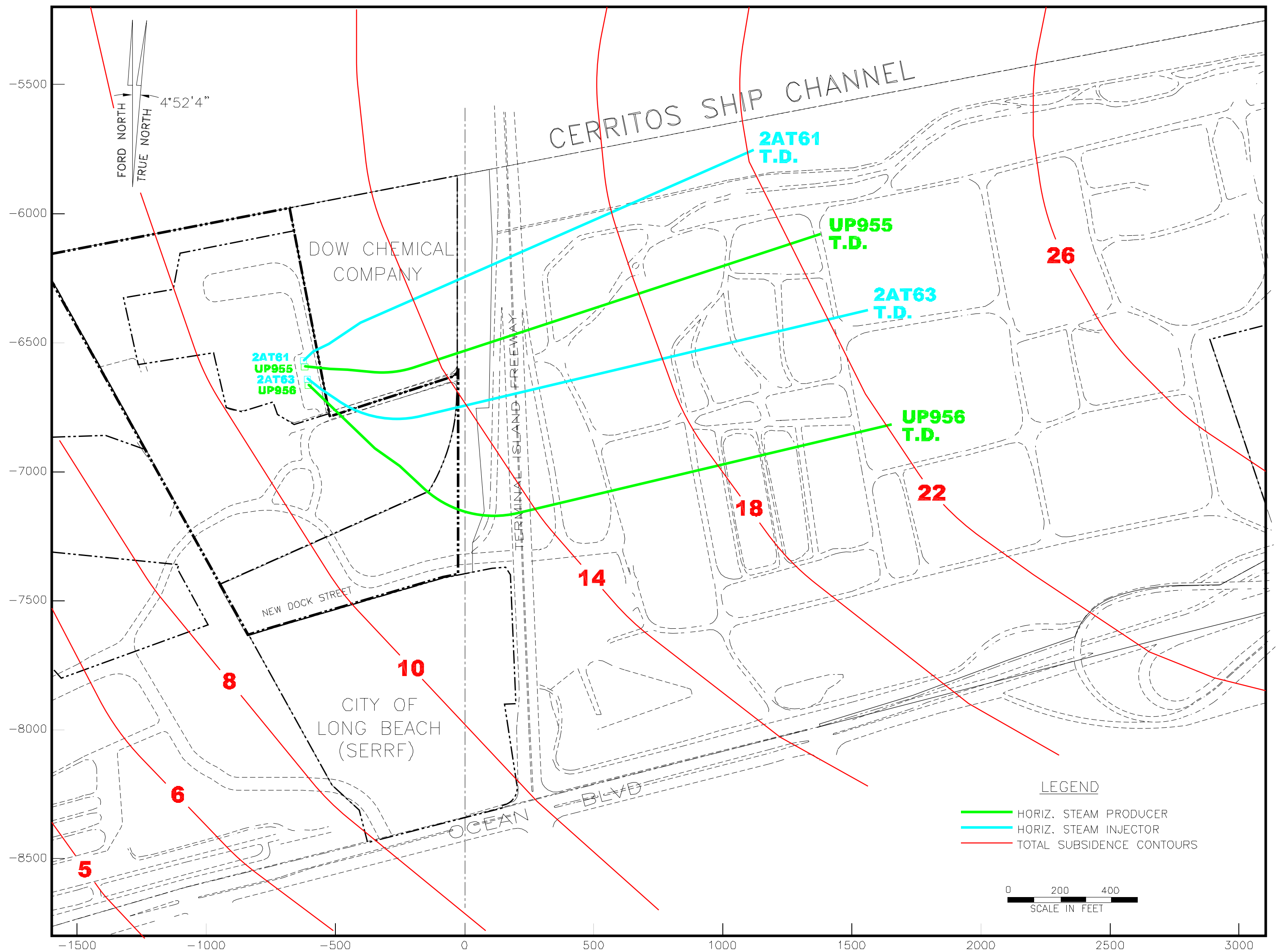


**Figure 6. Map showing the location of the fault block II horizontal wells in relation to the subsidence bowl. The red contour lines are total elevation loss in feet. The four horizontal wells were completed in an area of 14 to 22 feet of subsidence. The producing well courses are shown in blue, and the steam injection well courses are shown in green. The line of cross section A-B is shown.**

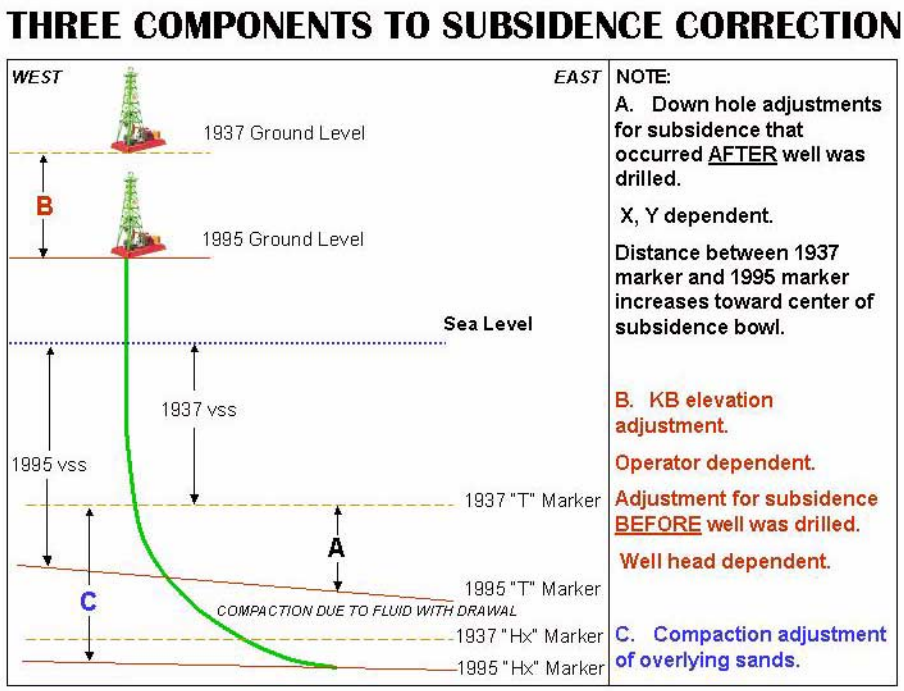


**Figure 7. The three components to subsidence correction. Adjustments must be made for rock compaction that has occurred after a well is drilled. The Kelly bushing must be corrected for subsidence that has occurred prior to drilling. Finally an adjustment must be made within the formation to correct the overlying sediments for compaction that has occurred below.**

injection. A 3-D deterministic reservoir simulation model that calculated mass balance and heat balance was used for injection conversion. Subsidence was halted and the area is currently very profitable, producing 1000 bbl/day net (159 $m^3$/day) with a gross of 21,000 bbl/day (3339 $m^3$/day). The next step was to see if these techniques could be applied to Fault Block V.

### Fault Block V Projects (Case Histories 2 and 3)

There are two horizontal well projects in Fault Block V. The first is in the Tar Zone where five horizontal wells were drilled. The second project is in the Upper Terminal Zone where a single well was drilled into the thin, shaley $Hx_0$ sand. The excellent accuracy of the 3-D geological model generated, and the usefulness of the computerized tools used to extract information from the model, greatly enhanced the success of both projects.

#### *Case History 1 (Tar Zone)*

As with the Fault Block II project, the 60+ year-old electric logs were reviewed and recorrelated dividing the Tar Zone into 14 sub-subzones. The log (Fig. 13) shows a portion of the stratigraphic section from probe hole well FJ-204. The “$S_4$” sand was chosen as the target because it shows the highest resistivity (oil saturation) and it is the thickest, continuous, clean sand across the fault block. A probe hole was drilled to verify reserves and not for horizontal placement.

A deterministic geological model was created from which the maps and cross sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than the earlier project, as the area where the horizontals were planned is unfaulted (Fig. 14).

The experience gained in Fault Block II and improvements to the software made modeling even easier. Areas of “no data” were controlled by adding interpretive “ghost” points through the 3-D viewer and then reconstructing the model. This interpretative technique cut modeling time significantly.

Data from one area of the model indicated an anomalous structural low. The survey and log picks appeared to be correct for a well located in the area of this “low.” The data point was honored and horizontal well J-201 was drilled into the area. It was apparent from the LWD curve separation and bed boundary intersections that the “T” shale was shallower than the model indicated. The offending well data was removed and the model was rebuilt

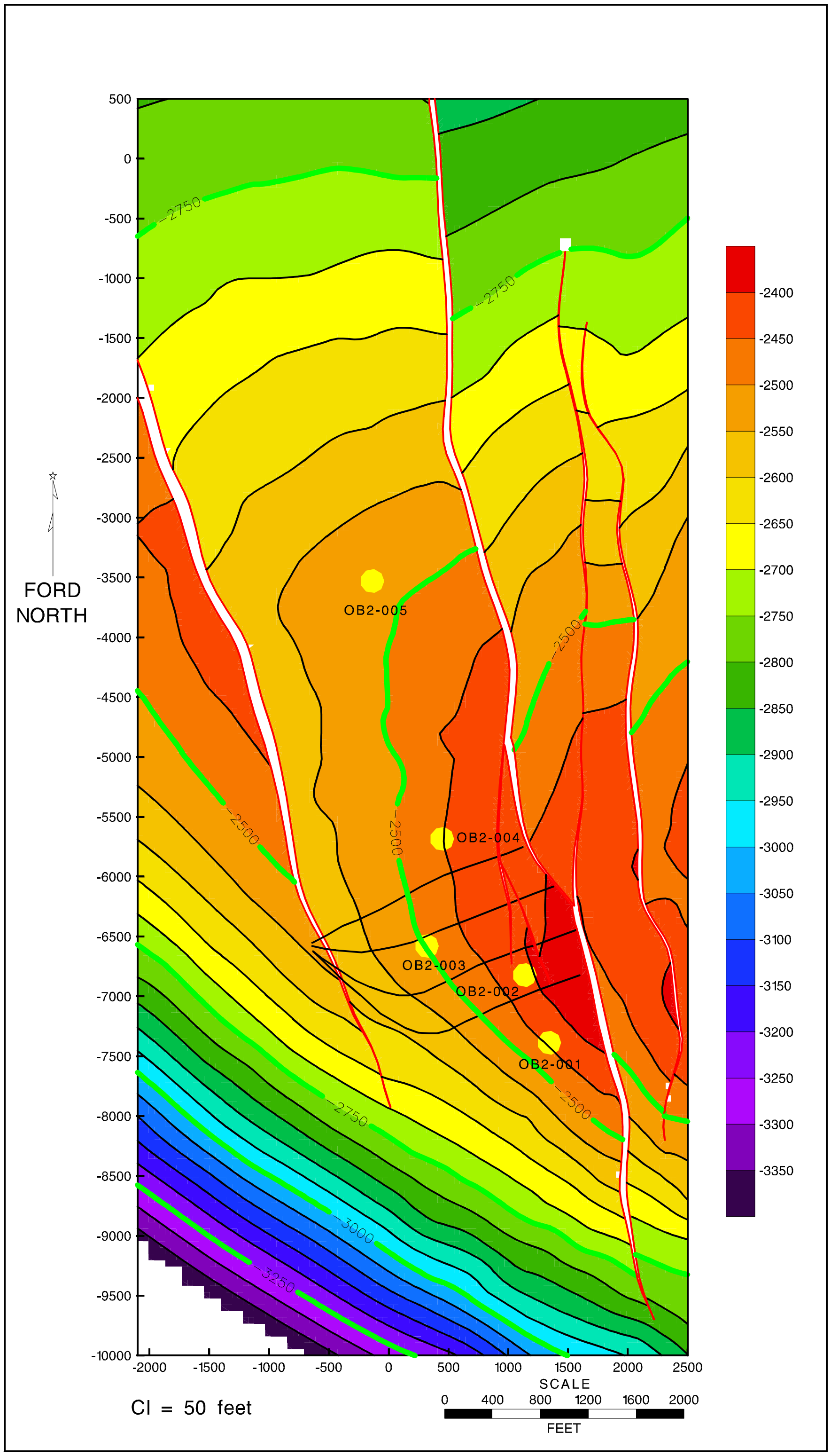


**Figure 8. Structure map on the "T" marker in fault block IIA. Observation and horizontal wells are shown. Shown are fifty-foot contour intervals from –2400 to –3400 feet below sea level.**

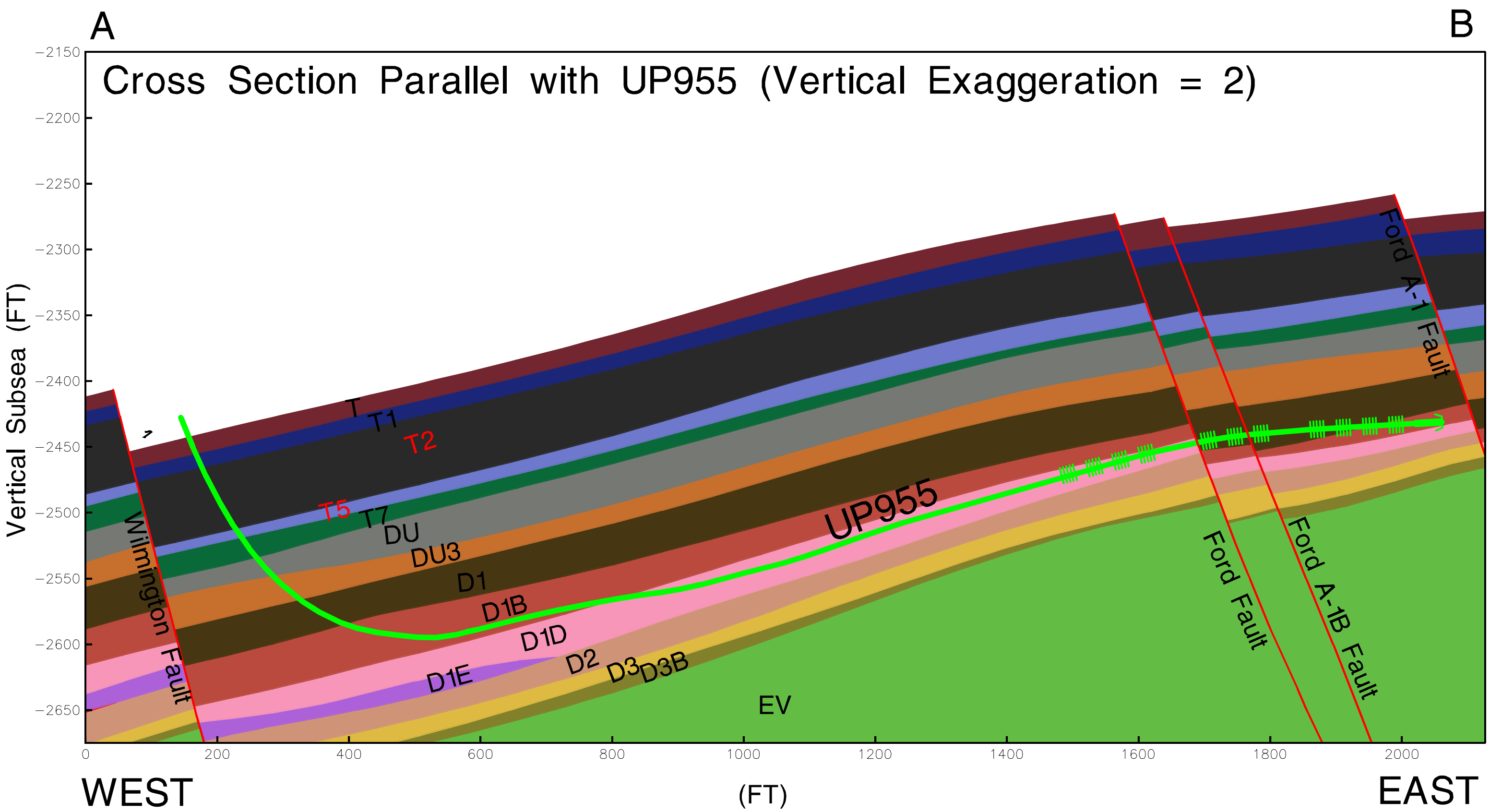


**Figure 9. Cross section A-B, which goes along the well course of UP 955. Perforations are shown on well course. The onlap of the D1E is shown and no detail below EV is shown. The section is scaled in feet and has a 2X vertical exaggeration. The location of the cross section can be found on Figures 3, 4, 6 and 8.**

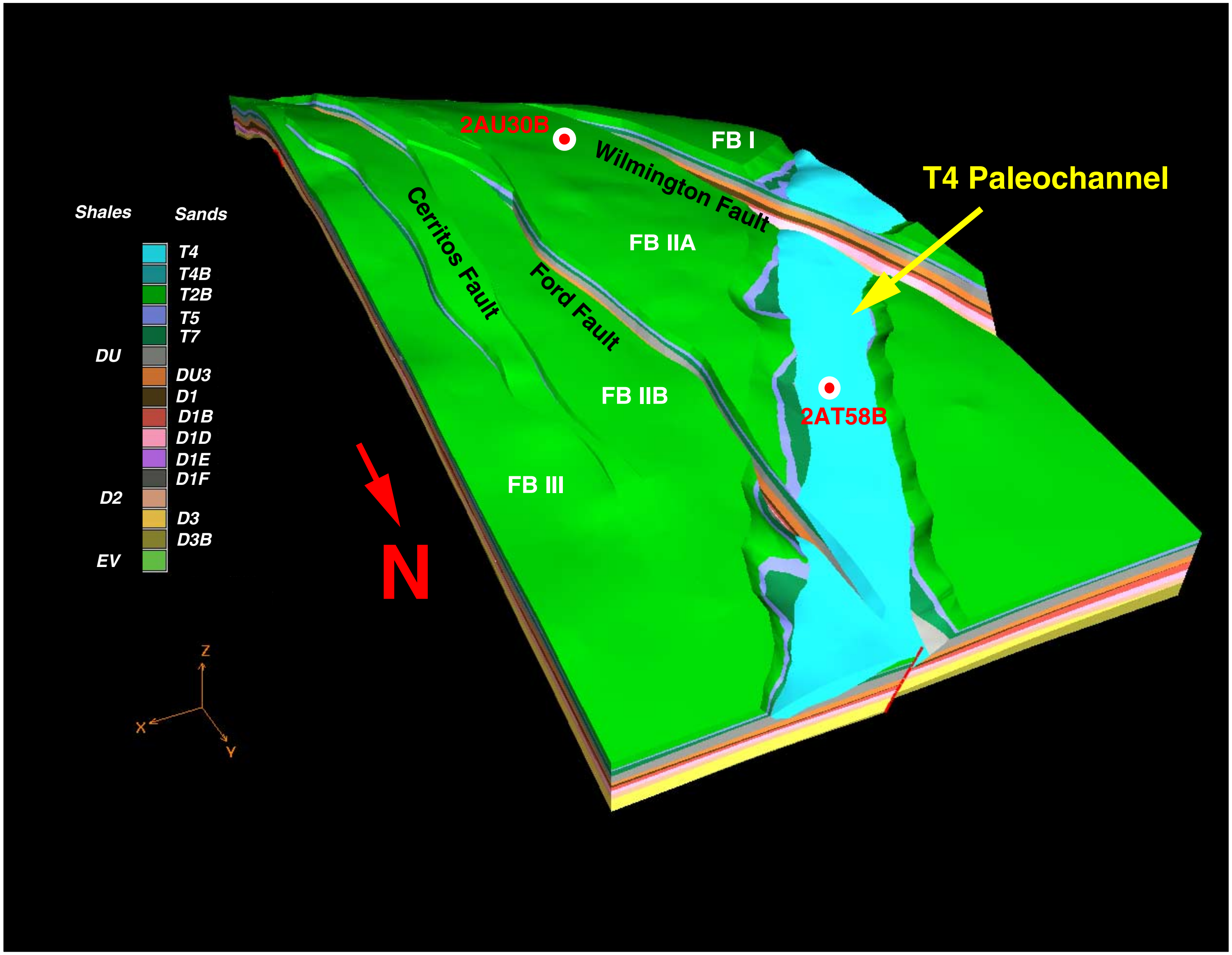


**Figure 10. Three-dimensional structural display on the T2 horizon in fault block II. The locations of the two type wells in Figure 5 are shown. The T4 paleochannel cuts through several horizons.**

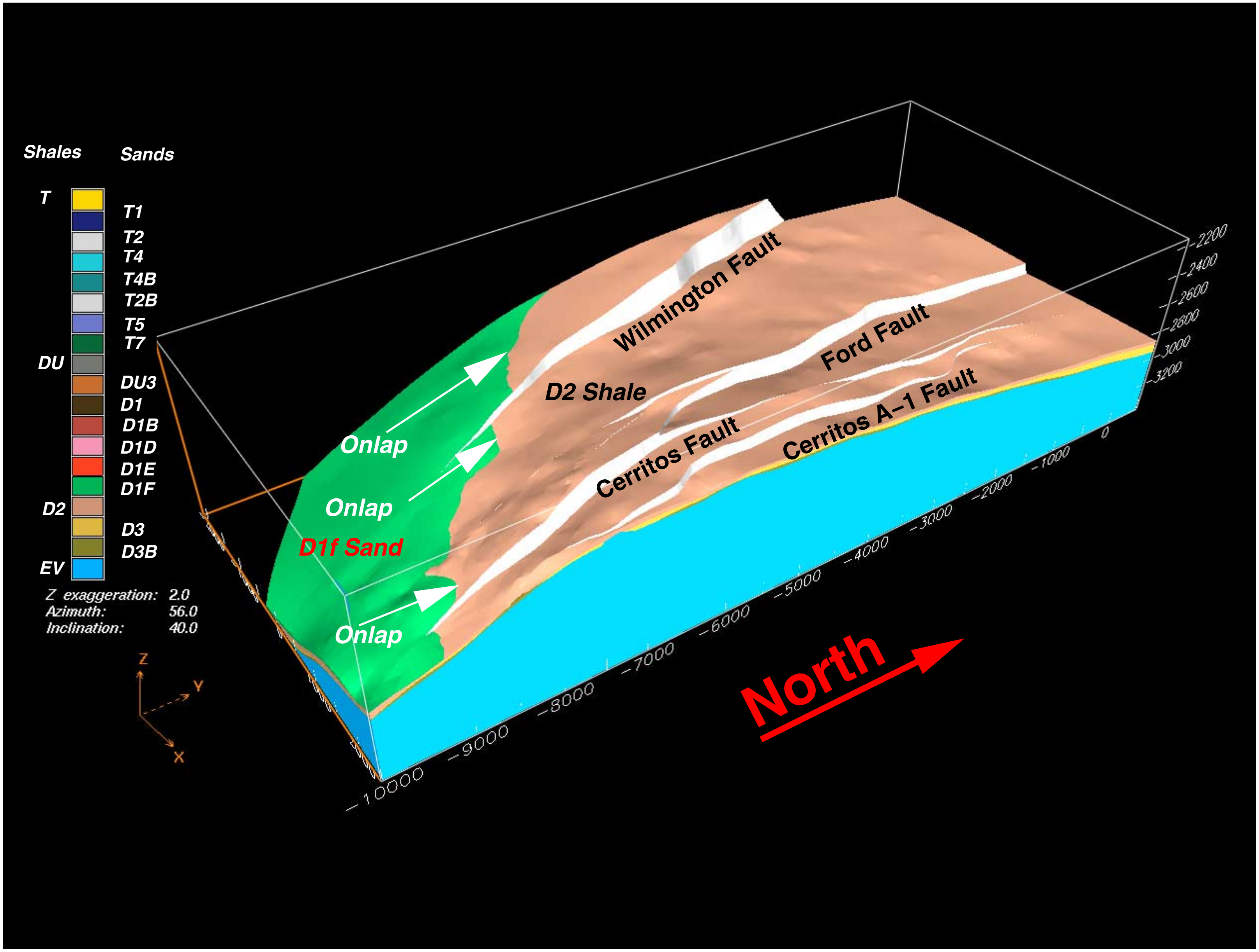


**Figure 11. Three-dimensional display of the D1F onlap onto the D2 shale in fault block II. The figure has a 2X vertical exaggeration and the units displayed are in feet.**

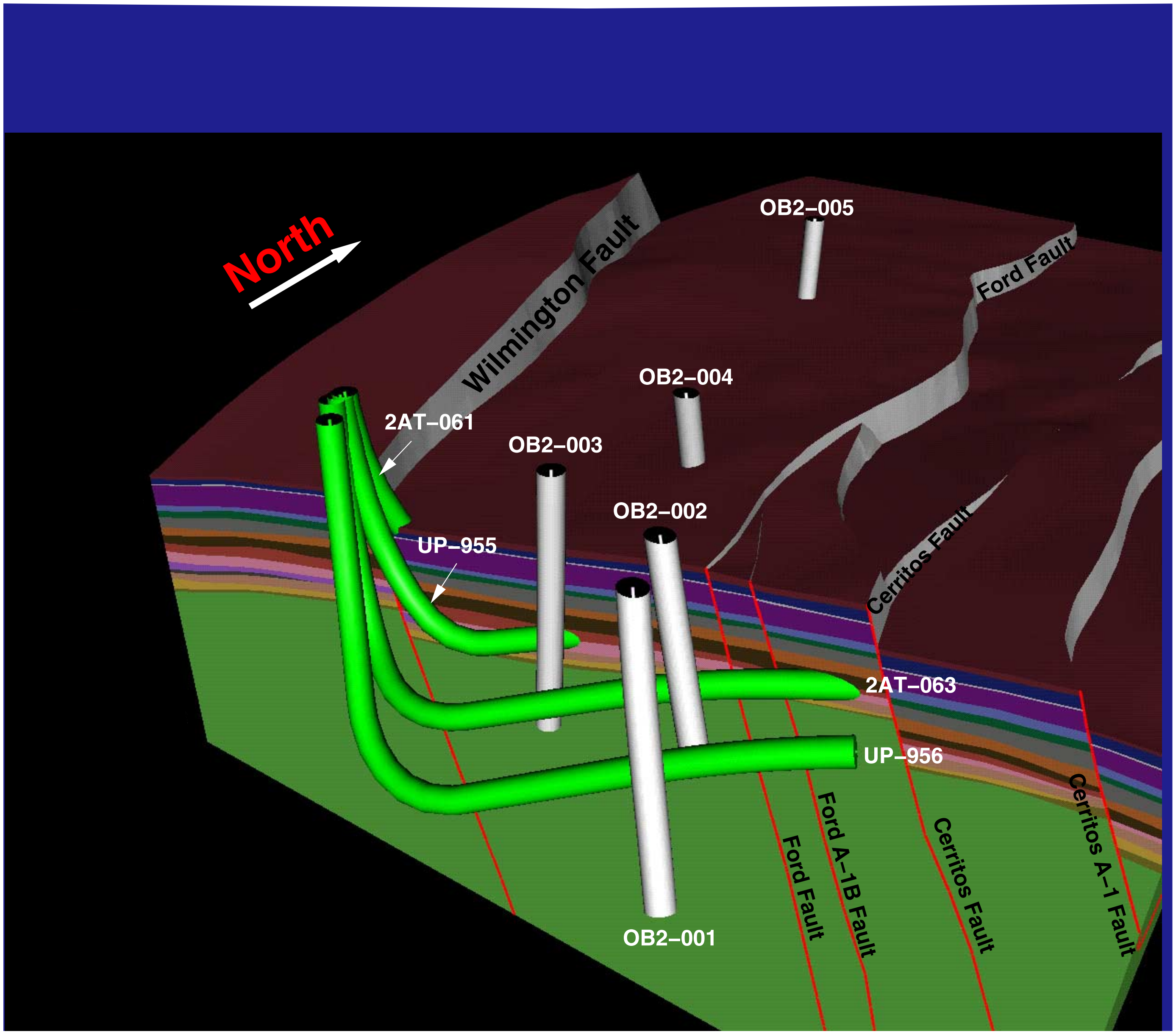


**Figure 12. Three-dimensional display of fault block II showing the locations of the wells drilled for the steamflood project. The figure has a 2X vertical exaggeration and the well bores are greatly exaggerated to enhance the visual impact of the well pattern.**

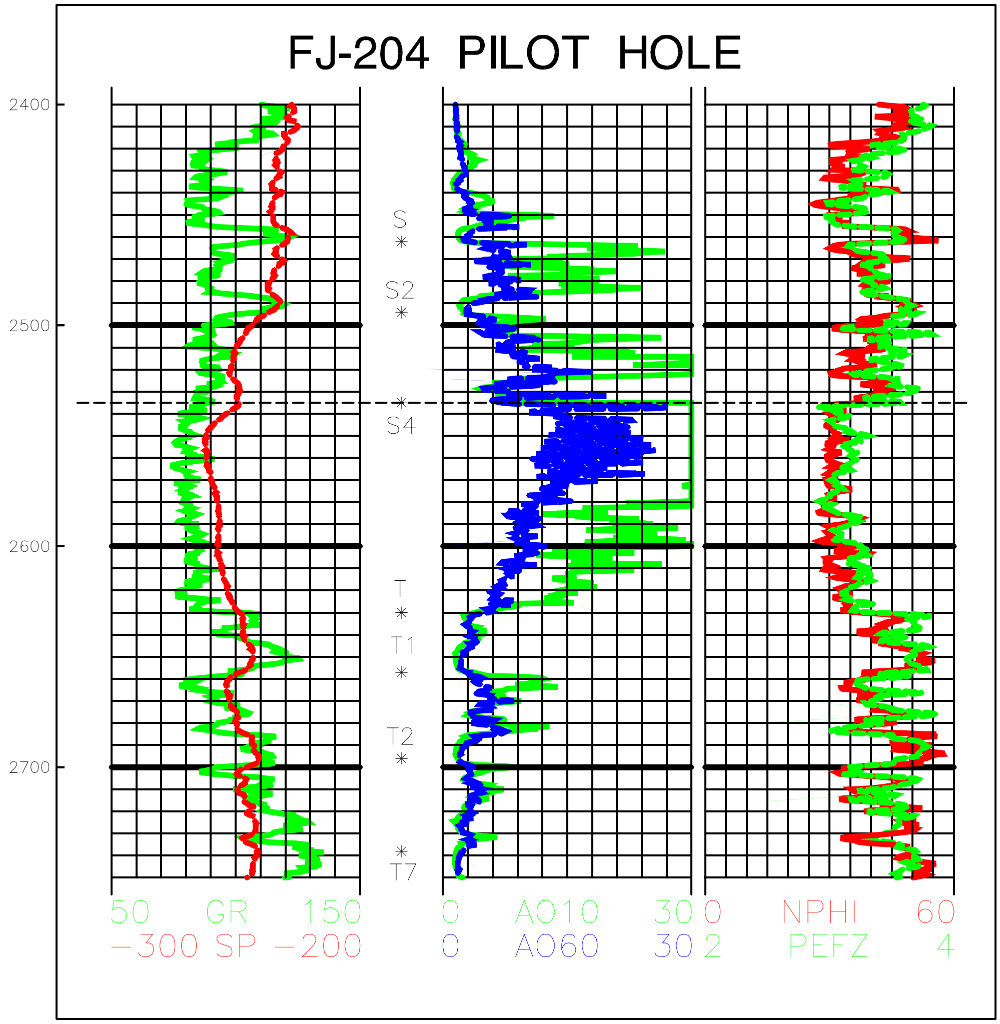


**Figure 13. Well log for FJ-204 pilot hole in fault block V Tar zone. The S and T section is shown. The S4 sand is the target. The location for this well is shown on Figure 14.**

based on the horizon picks from well J-201. Because this remodeling can now be done in almost real-time, the geologist revises the model as drilling proceeds. An improved model is built if needed, as each new well is completed. Well J-201 did not go as planned; determining the completion interval was difficult until the other horizontal wells and their perforations were displayed in 3-D (Fig. 14).

The 3-D model in Figure 13 is "bench cut" and shows the five horizontal wells and their perforations. The goal was to keep the wells parallel to the top of the "T" shale to maximize recoverable reserves from the superjacent "$S_4$" sand. The maps, cross sections and geological model were all used to place the horizontal wells accurately. Figure 14 shows the cross section for well J-203.

Overall, the Tar V drilling project (case history 3) was a major technical and economic success. Based on what was learned in Fault Block II and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. It was easy to anticipate the highs and lows of the horizons and the locations of bed boundaries. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, no pilot holes (except for FJ-204) were necessary. As a result time and money were saved.

The drilling team appreciated having visuals at the rig site because they stimulated better feedback and established a clearer understanding of the geology encountered. They could see what a particular directional tool set accomplished and thus refine drilling techniques for added

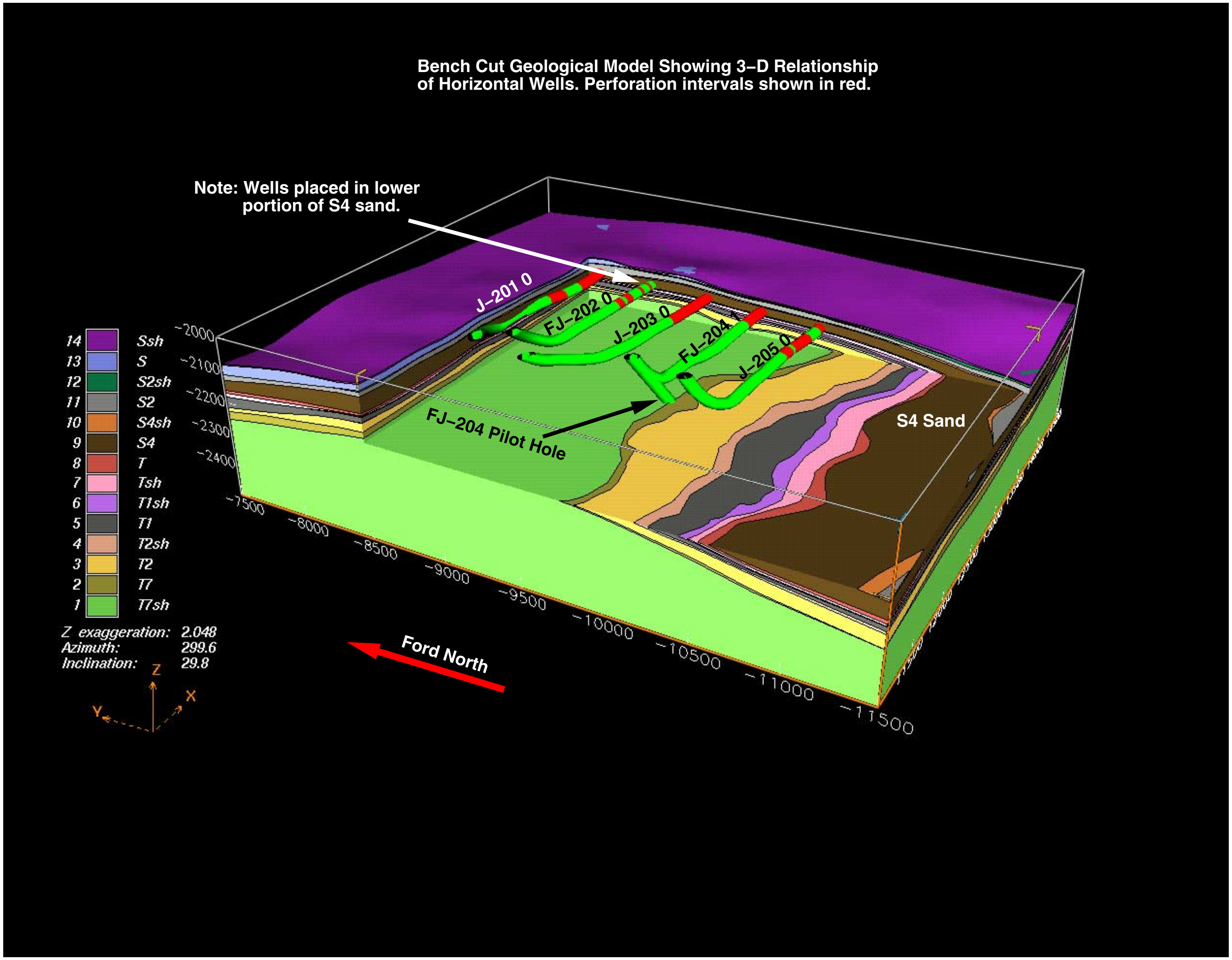


**Figure 14. Three-dimensional bench cut of the fault block II Tar zone showing the steam flood project in the S4 sand. This nearly horizontal area has a 2X vertical exaggeration.**

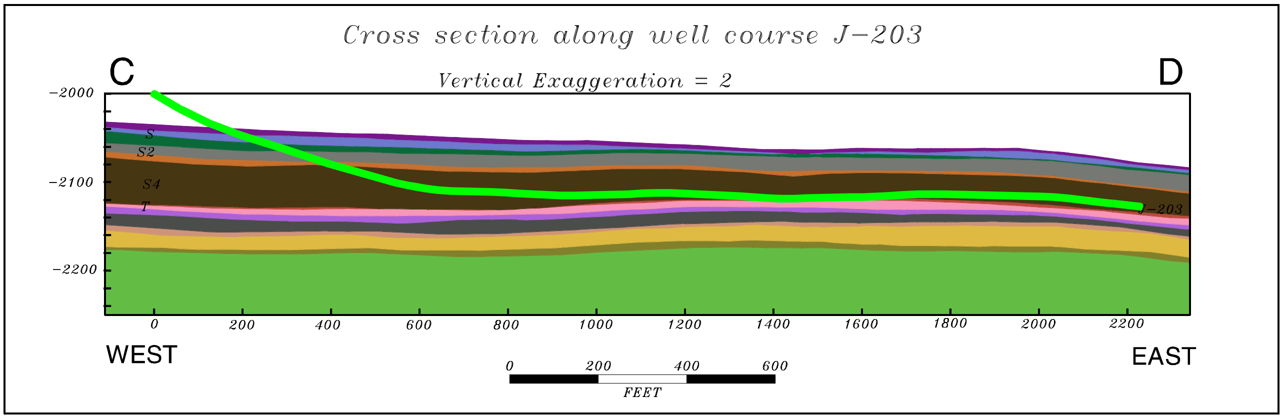


**Figure 15. Cross section along well course J-203. The well was placed as close to the bottom of the S4 sand as possible to increase recovery. See Figure 14 for the location of well J-203.**

efficiency. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well budget was based on the Fault Block II wells. There was an average savings per well of US$12,400 on directional costs and US$18,000 due to fewer drilling days. In total, US$152,000 was saved on the five horizontal wells drilled. Because of the monetary savings and the drilling team's confidence in the 3-D model, all of the laterals were extended an extra 12%, on average, effectively increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank $m^3$ (STCM) of oil.

The five horizontal wells were steam cycled and placed on production (Fig. 17). Two of them, FJ-204 and FJ-202, were placed on permanent steam injection. A-186 3, A-195 0 and A-320 0, each a 30+ year-old well, remained on production within the steam project boundaries as of March 1996, averaging 16 bbl/ day (2.5 $m^3$/day) net with 200 bbl/day (31.8 $m^3$/day) gross, at an average water cut of 92%.

When the horizontal project was initiated, this area only had about five years of remaining economic life under waterflood, and recoverable reserves were estimated at 75,000 bbl (11,924 $m^3$). The average pool water cut prior to steaming was 95%. The water cut in the project area was 81% in 1998 and is currently 92% (July 2000), and another 1,700,000 bbl (270,283 $m^3$) of reserves have been added to the Tar V pool.

Steam communication to the existing waterflood wells, from cyclic steam injection into wells FJ-202 and FJ-204, resulted in a six- to ten-fold net production increase in the old waterflood wells (Fig. 17). Peak annual production rates under steam drive are forecast at 590 bbl/ day (93.8 $m^3$/day) for the horizontal project. For the first four months of 1998 the average oil production was 698 bbl/ day (111 $m^3$/day). In July of 2000 the average oil production was 242 bbl/day (38.5 $m^3$/day). The production rates should be several times greater, but each well's performance has been hindered by fluid levels exceeding 1500 ft. The high fluid level suppresses oil production and also cools the produced fluids, resulting in lower recoveries. Plans are underway to replace the pumps. The success of the program can be seen in Figures 16, 17 and 18 which show how the project area has changed over time. Note in Figure 16 that prior to steaming the average net was about 14 bbl/day. By January 1998 (Fig. 17) the average net was over 150 bbl/day. In August of 2000 the average net is still over 100 bbl/day.

The 3-D techniques used contributed significantly to the success of the Tar Zone horizontal project. The importance can be seen by assuming a 50% recovery factor. Every foot above the target is equivalent to 15,876 STB (2,524 STCM) in lost reserves (Phillips, 1996). At US$14/ bbl oil, being off as much as five feet vertically would equate to U.S.$1.1 million in lost revenue.

*Upper Terminal Zone: $Hx_O$ Thin Sand Sequence*

The $Hx_O$ sands of Fault Blocks V and VI were reviewed as part of a U.S. Department of Energy (DOE) Class III Short-Term Project (Phillips, 1998). The project proposed using new reservoir characterization tools and techniques to exploit bypassed oil. The new technologies included detailed reservoir characterization, 3-D geologic modeling, geosteering in thin heterogeneous beds and modeling the LWD responses (MacCallum and others, 1998).

A deterministic geological model was created to define the $Hx_O$ layer and the horizons above and below it ($Hx_1$ above, $Hx_2$ and Hx below). The sand percentage was calculated for each data point. A 3-D property model was

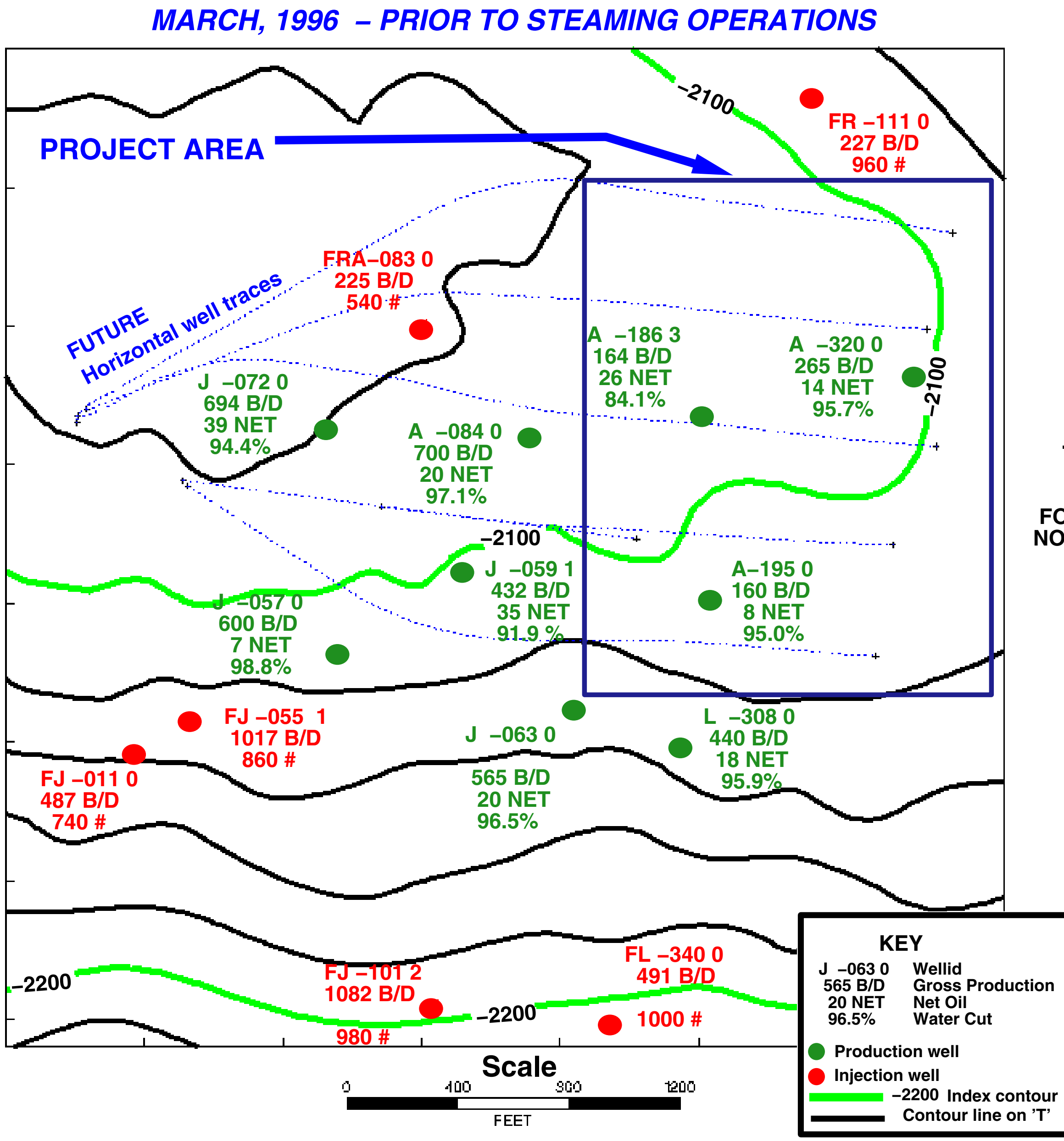


**Figure 16. Fault block V Tar zone waterflood configuration. Production and cut data are shown prior to steaming operations. Each production well is labeled in green with the name, gross production, net oil production and water cut. In red the injection wells are labeled with well name, injection rate in barrels per day and the surface pressure. Structural contours are vertical subsea on the "S" sand with a twenty-foot contour interval. Ford north refers to a local Cartesian coordinate system.**

created by gridding the sand percentage in 3-D space using the top and bottom of the $Hx_O$ as confining surfaces (Fig. 19). The original oil saturation (So) was similarly property modeled to identify target areas for exploitation.

A display of the So model and wells drilled in the 1980s clearly showed that Fault Block VI was effectively drained but that Fault Block V still had reserves. The difference between the original So and that indicated by the 1980s wells was quantifiable. The So calculated from the old wells was decremented, the two data sets were combined, and Fault Block V was again property modeled (Fig. 20). The sand percentage model and the So model were combined and the original oil in place was calculated to be 3.4 million STB (540,566 STCM). The current oil in\

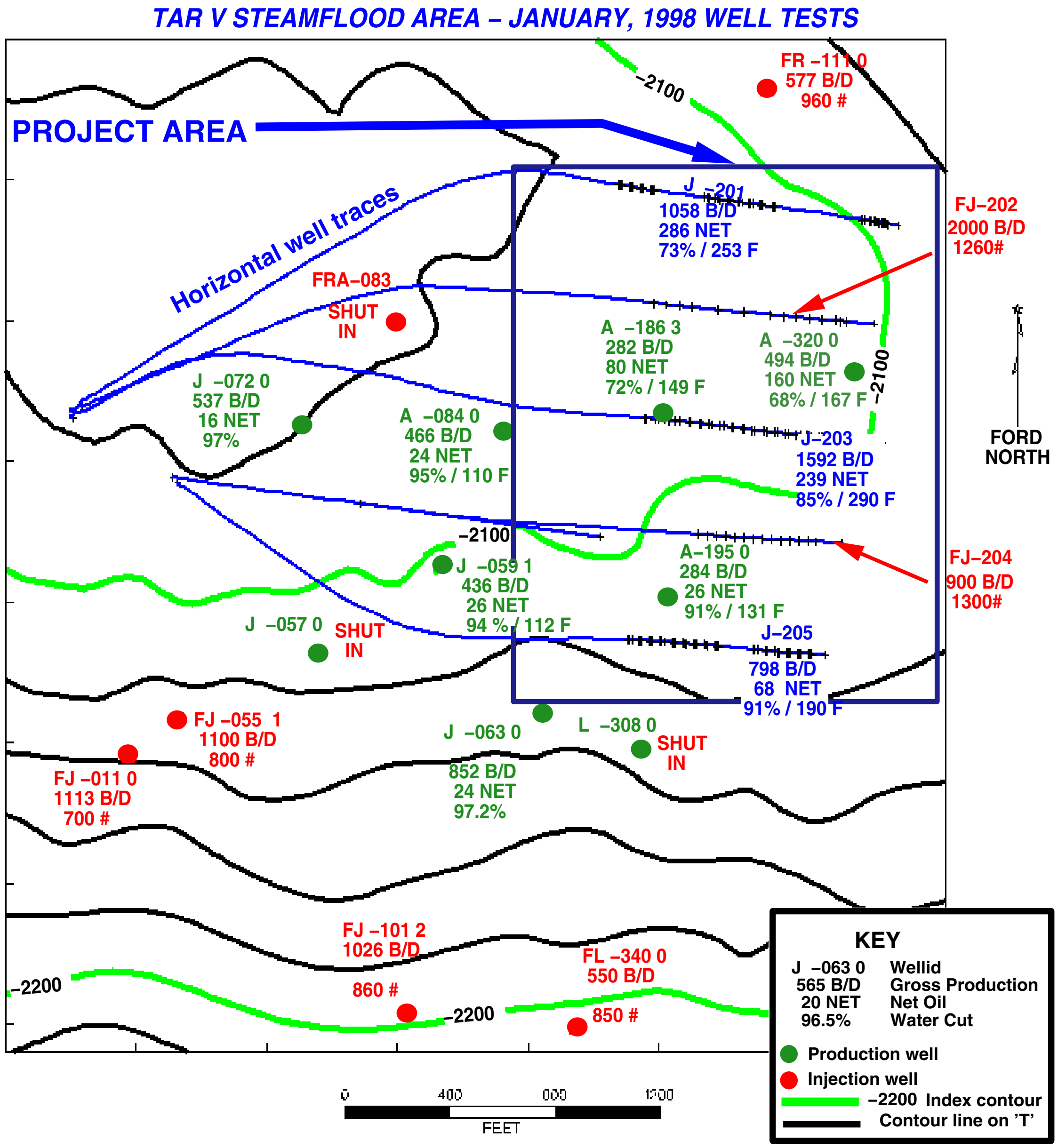


**Figure 17. Fault block V Tar zone waterflood configuration. Production and cut data for January 1998.**

place was calculated and the reserves were reduced to 2.8 million STB (445,172 STCM) (Phillips and Clarke, 1998). Obviously, significant reserves remain.

Based on the geological model, the block engineer proposed that a horizontal well be drilled within and adjacent to the modeled area along the structural high. An existing well bore was sidetracked with a horizontal lateral to capture hydrocarbon reserves uneconomically recoverable with conventional methods. Idle well J-017 was selected for drilling the high dogleg horizontal well and a production rig configured for drilling was used to keep costs to a minimum. By investigating to the west of the original $Hx_O$ project area, it was determined that the target sand thins and shales out to the west, thus reducing oil saturation. Electric logs from wells penetrating the area as far as 1,000 ft (305 m) to the west were correlated and a second 3-D geological model was created.

A facies boundary was delineated to constrain the planned well course within the higher water saturation (So) target. The $Hx_O$ layer was subdivided and two sand lobes were identified within the $Hx_O$ layer. The $Hx_{OJ}$ and

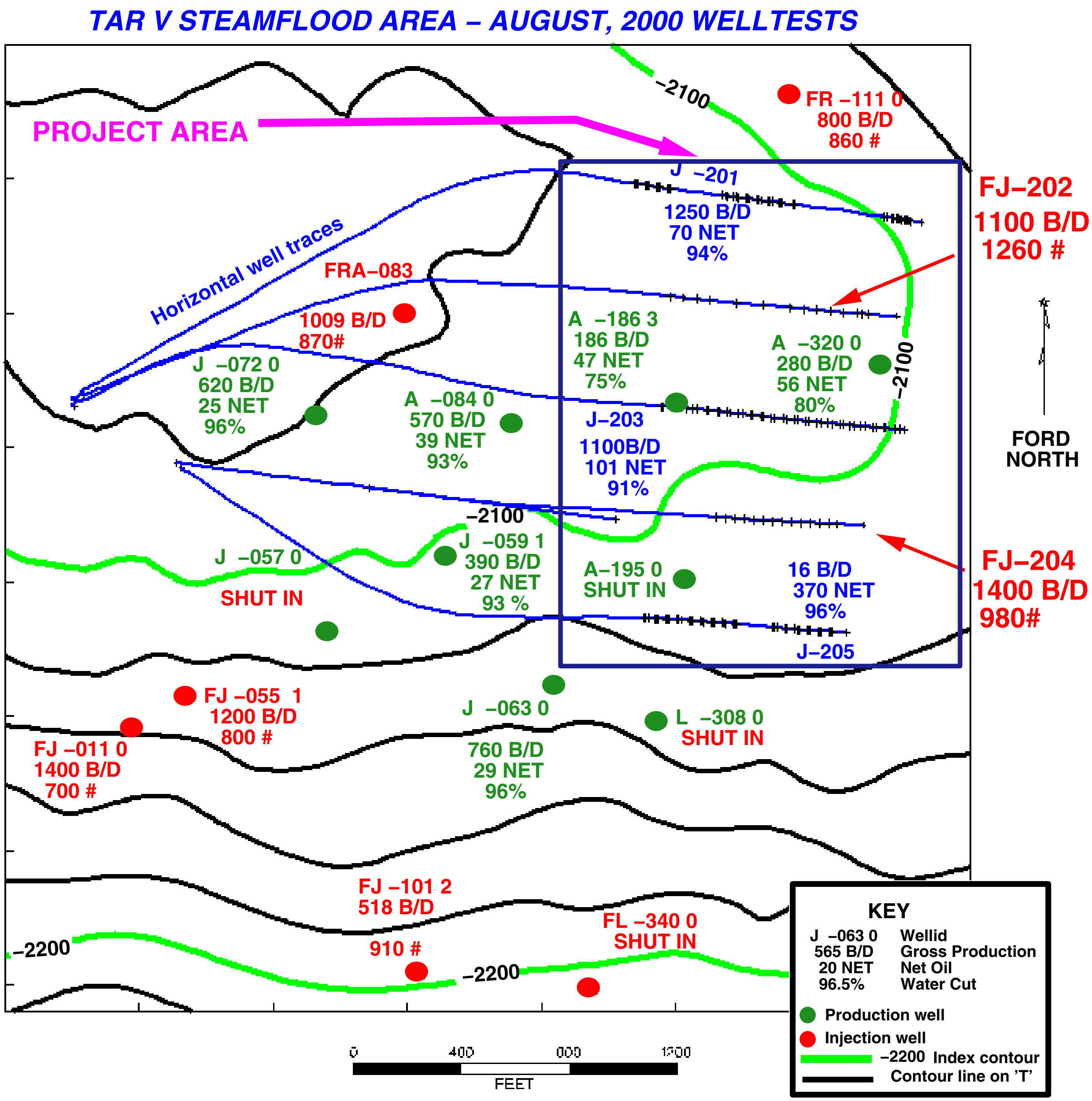


**Figure 18. Fault block V Tar zone waterflood configuration. Production and cut data for August 2000.**

$Hx_{OB}$ horizons were defined and added to the 3-D model. Maps and cross sections were extracted from the 3-D model and used for well planning (Fig. 21).

A cross section along the well course was created for the geologist. The directional vendor required three linear cross sections for drilling because the well plan showed a 'U-turn' (Fig. 22). Stratigraphic sections consisting of adjacent wells were also created to help in geosteering. Both "paste up" and digital varieties were used.

Structure maps were created on the $Hx_1$, $Hx_O$ and newly defined $Hx_{OJ}$ (Fig. 23) and $Hx_{OB}$ sands. These plots, as well as the 3-D model were used as tools to help geosteer. Ultimately, they had to be used for directional control due to rig site problems.

A recently introduced, probe-based Multiple Propagation Resistivity (MPR) device was used to provide LWD geosteering as well as directional information. This resistivity sensor was part of a slim hole, positive-pulse-type

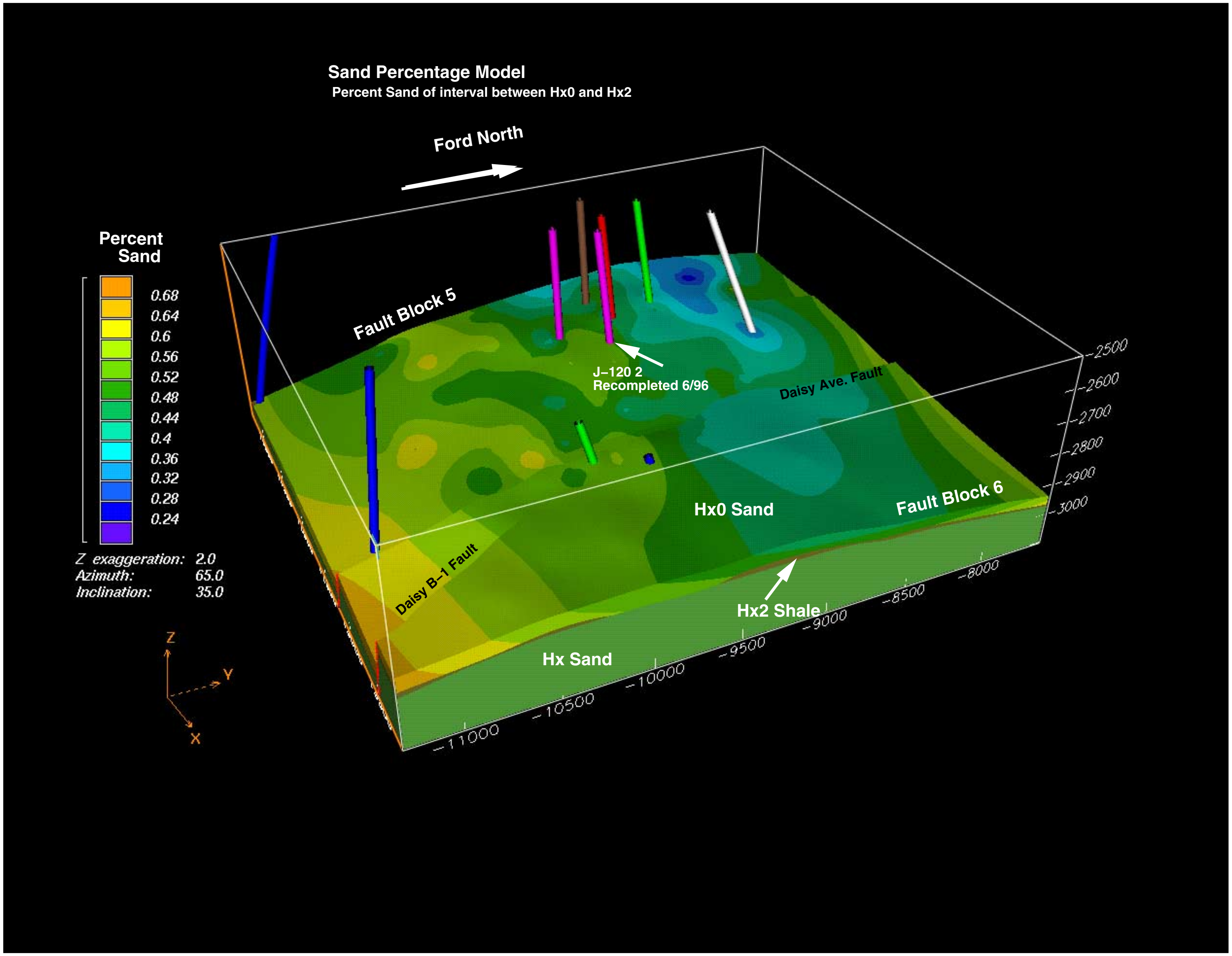


Figure 19. Sand percentage three-dimensional display for the $Hx_0$ to $Hx_2$ interval of the Terminal zone in fault block V. Cartesian coordinate system is in feet and there is a 2X vertical exaggeration.

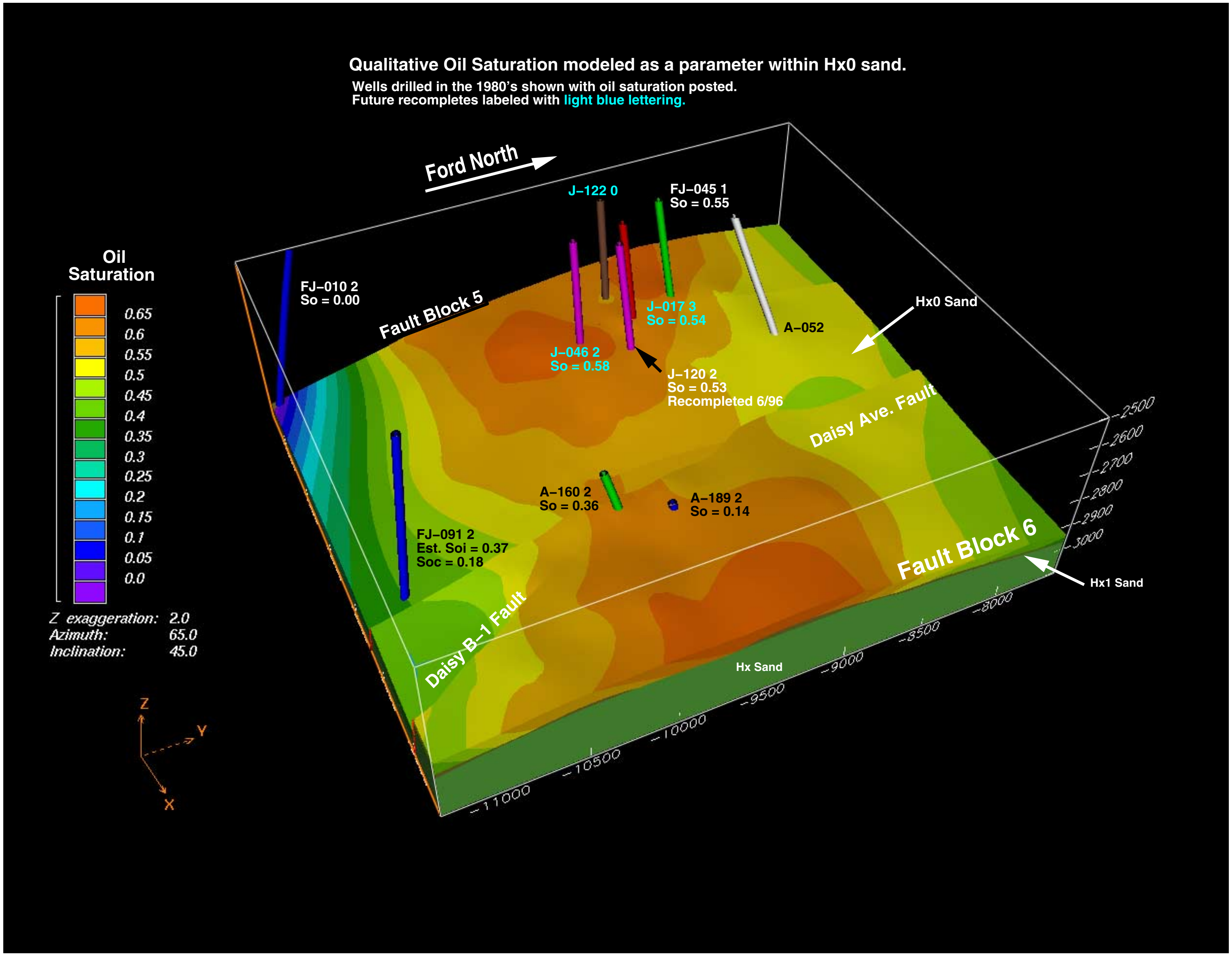


**Figure 20. Qualitative oil saturation (So) three-dimensional display for the $Hx_0$ sand of the Terminal zone in fault block V. Cartesian coordinate system is in feet and there is a 2X vertical exaggeration. Oil saturation is posted with each well.**

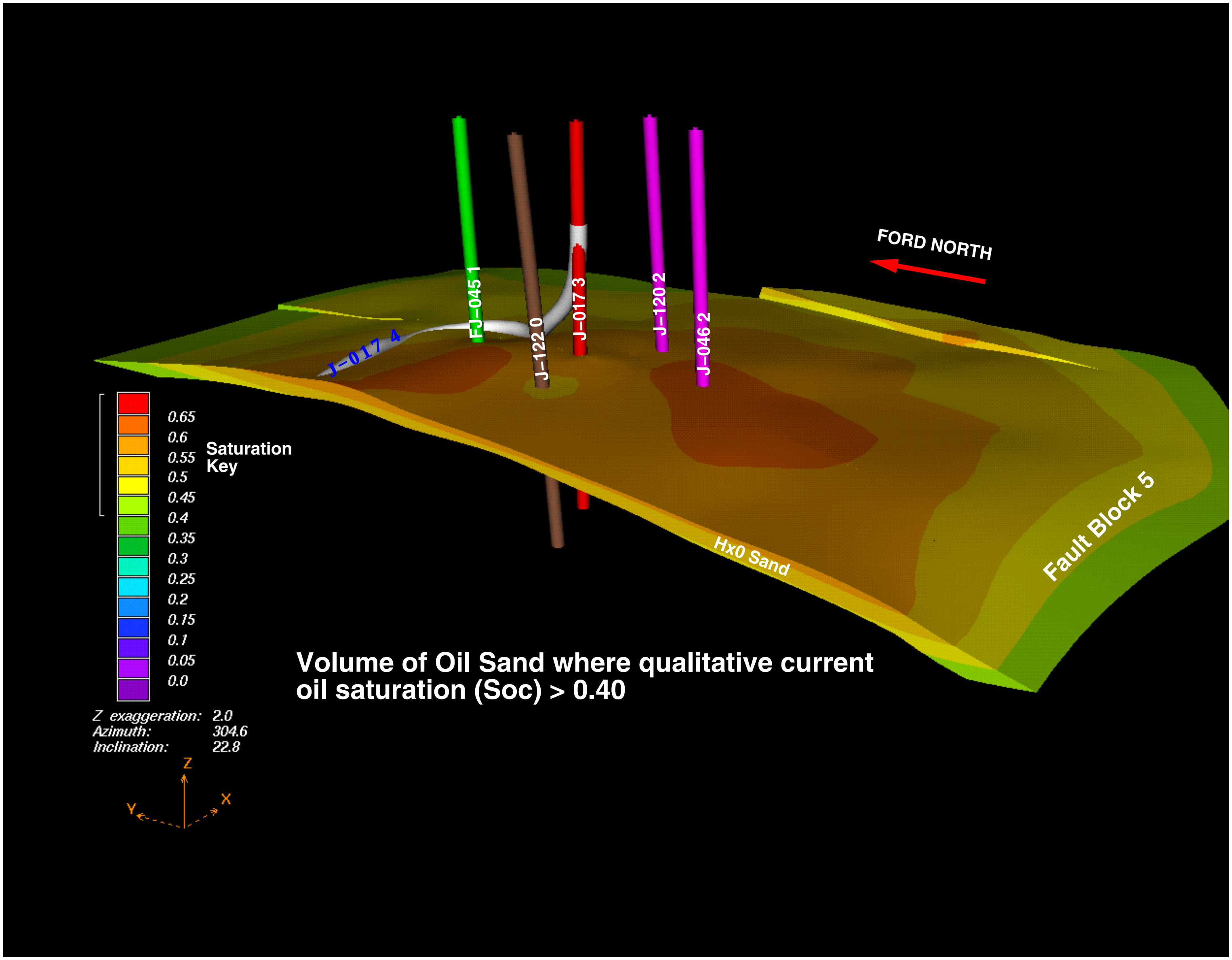


**Figure 21. Three-dimensional display of the fault block V Terminal zone showing the J-017 well and surrounding wells. The oil saturation is mapped on the $Hx_0$ sand. This is essentially a net pay map for the $Hx_0$ sand.**

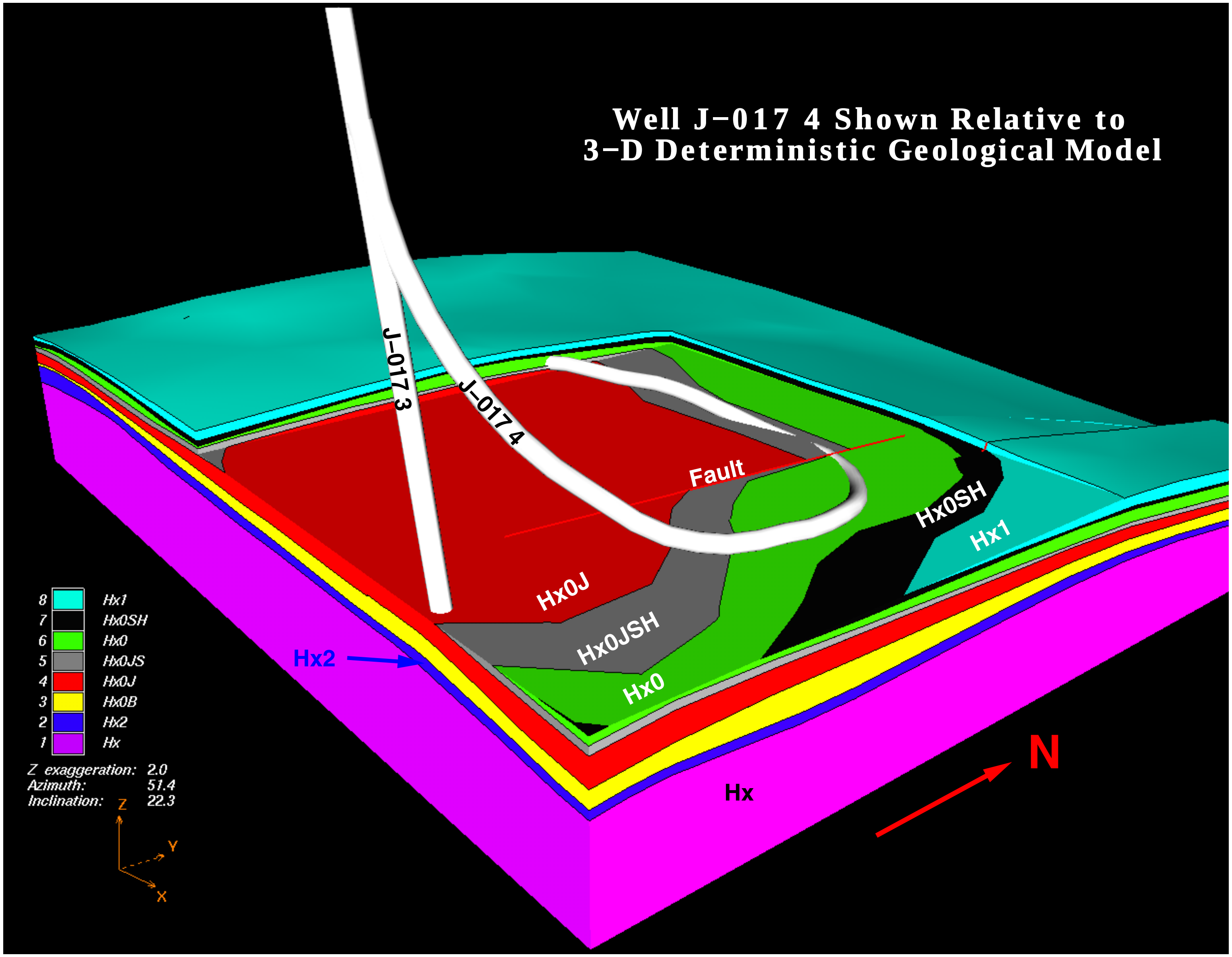


**Figure 22. 3-D bench cut display showing the J-017 4 tight radius sidetrack into the $Hx_0$ sands.**

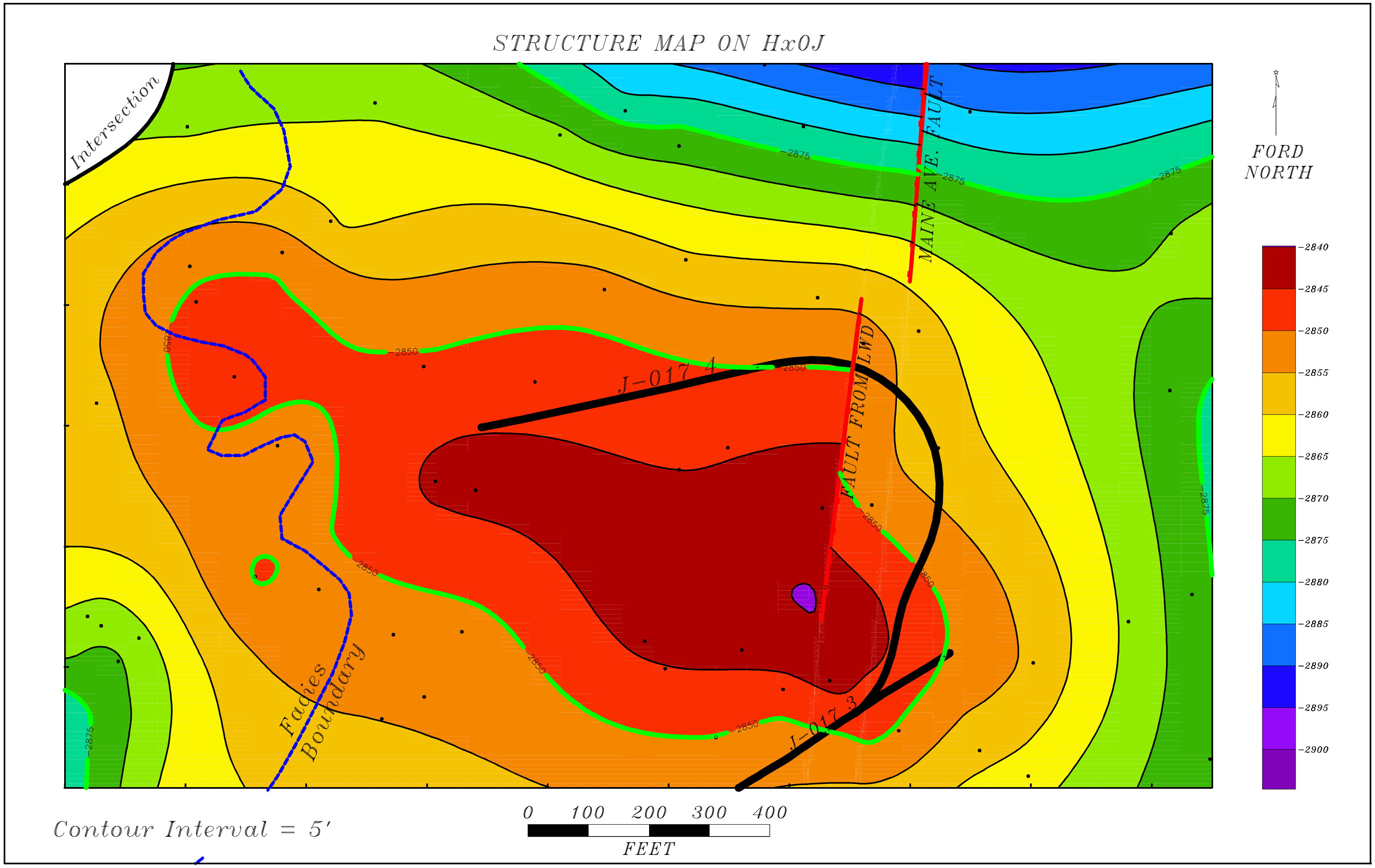


**Figure 23. Structure map on the $Hx_{0J}$ sand showing the well course for J-017 4. The sand shales out and merges with the $Hx_{0J}$ shale in the western portion of the area. Ford North refers to the north in the antiquated Henry Ford Cartesian Coordinate system. Five-foot contour intervals are in feet vertical sub-sea. A small fault was detected during drilling and was incorporated into the model.**

MWD/LWD system that was used instead of "carrier wave" tools because of their smaller size (the tool diameter is 4 3/4 in.). These newer tools have well-integrated surface equipment, are battery-powered, and provide more reliable telemetry signals. The MPR tool is a four-transmitter, two-receiver array that provides a total of eight compensated resistivities at 2 MHz and the deeper reading 400 kHz, in boreholes as small as 5 7/8 in. For additional geosteering control an inclinometer and gamma ray scintillation detector are below the MPR sub. The well was successfully placed within two sand lobes of the thin sequence by geosteering using the LWD data.

The interval is thin and shaley (total thickness of 17 ft or 5.2 m) and the LWD showed the "anisotropic" effect throughout the log (Fig. 24). The resistivity response in anisotropic conditions is similar to conductive invasion in that the short-spaced measurement reads less than the long-spaced for both the phase difference and attenuation resistivity measurements. However, the shallow-reading, phase difference resistivity curves measure a higher resistivity than the deep-reading attenuation curves for both frequencies and spacings. This curve order is not indicative of conductive invasion, but of anisotropy (Meyer and others, 1996). The presence of anisotropy plus formation heterogeneity complicated the interpretation of the LWD data so the geosteering team had to rely significantly on the geological model.

A simple layer model was used for previous horizontal well projects. The sand package was thick enough for the LWD to give a unique, easily interpretable response. The $Hx_O$ "sand" is divided by a continuous shale. The upper sand, referred to as the $Hx_O$, is 6 ft (1.8 m) thick and the lower sand, $Hx_{OJ}$, is 8 ft (2.4 m) thick. Again, the horizontal well was successfully placed into each of these sands.

Post-well analysis and support was excellent. The LWD analyst spent significant time studying the LWD data and explaining the results. For wells drilled parallel to bedding, adjacent beds and formation anisotropy were significant factors in the log response. The anisotropy was quantified, the horizontal and vertical resistivity was determined, and a mathematical model of the LWD response was created (MacCallum and others, 1998).

The 3-D model was refined based on conclusions reached by collaboration between the LWD analyst and geologist. A significant step toward interpreting the data was to model the shales above the $Hx_O$ and $Hx_{OJ}$ sands. A new anisotropy inversion algorithm and the inclusion of shales in the geological model allowed for a clearer understanding of the 2 MHz resistivity responses to the formation and their boundaries.

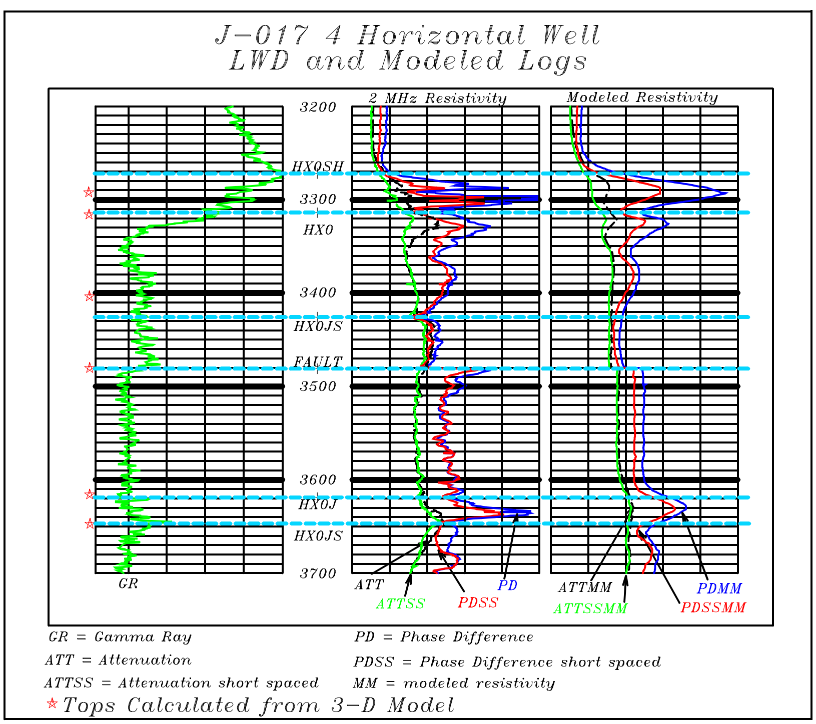


**Figure 24. J-017 4 horizontal well log. LWD and Modeled logs are shown. An excellent match was obtained. The location of this well is seen on Figure 23.**

A fault was also identified during this process. The fault geometry was determined using the 3-D model and further mathematical modeling of the LWD. There was a good correlation between the tops calculated from the 3-D geological model and the tops selected from the LWU log. The average vertical distance between the bed boundary calculated from the 3-D geological model and the well as determined by the LWD log is less than 0.25 ft (0.08 m)!

## Conclusions

The geologist working with carefully characterized rock data and 3-D modeling and visualization techniques adds greatly to the horizontal drilling team. The highly accurate 3-D visualizations of the reservoir greatly increase the confidence factor of the team thus enabling Wilmington Field reserves to be maximized.

To be effective, horizontal wells require precision placement. 3-D models help isolate data inconsistencies, while 3-D viewers are good for adding data to correct the geological model. Once the final geological model is created, the drilling team can use the resulting 3-D visuals with confidence to improve drilling techniques and directional control. Post-well analysis of the LWD data also is facilitated using 3-D geological models.

## Acknowledgments

We would like to acknowledge the help and support of: Terry Smith, president of Tidelands Oil Production Company: Jim Quay, Steve Siegwein, Scott Walker, Scott Hara, Rudy “Bud” Payan, Chris Parmelee: technical engineering staff at Tidelands Oil Production Company, Dennis Sullivan, director of the Department of Oil Properties: Donald Mc Callum, Baker-Hughes Inteq; Art and Tamara Paradis and Heather Kelley of Dynamic Graphics Inc: Computer modeling was done with DGI EarthVision on an SGI Iris Indigo workstation.

## References

Ames, L. C., 1987, Long Beach oil operations-a history, *in* D. D. Clarke and C. P. Henderson, Geologic field guide to the Long Beach Area: Pacific Section AAPG, p 31-36.

Biddle, K. T., 1991, The Los Angeles basin: an overview, *in* K. T. Huddle, ed., Active Margin Basins: AAPG Memoir 52, P. 5-24.

Blake, G. IL, 1991, Review of the Neogene biostratigraphy and stratigraphy of the Los Angeles basin and implications for basin evolution, in K. T. Biddle, ed., Active margin basins: AAPG Memoir 52, p. 135-184.

Blesener, J. A., and C. P. Henderson, 1996, New technologies in the Long Beach Unit, *in* D. D. Clarke, G. E. Otott, Jr., and C. C. Phillips, Old oil fields and new life: a visit to the giants of the Los Angeles basin: Pacific Section AAPG, p. 45-50.

California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, 1999, 1998 annual report of the state oil and gas supervisor: California Department of Conservation, Sacramento, 269 P.

Clarke, D. D., 1987, The structure of the Wilmington oil field, *in* D. D. Clarke and C. P. Henderson, eds., Geologic field guide to the Long Beach area: Pacific Section AAPG, p. 43-56.

Davies, D. K., and R. K. Vessell, 1997, Improved prediction of permeability and reservoir quality through integrated analysis of pore geometry and openhole logs: Tar zone, Wilmington field, California: Society of Petroleum Engineers, SPE Paper 38262, 9 p.

Davies, D. K., R. K. Vessell, and J. B. Auman, 1997, Improved prediction of reservoir behavior through integration of quantitative geological and petrophysical data: Society of Petroleum Engineers, SPE Paper 38914, 16 p.

Henderson, C. P., 1987, The stratigraphy of the Wilmington oil field, *in* D. D. Clarke and C. P. Henderson, eds., Geologic field guide to the Long Beach area: Pacific Section AAPG, p. 57-68.

Koerner, R. K., D. D. Clarke, S. Walker, C. C. Phillips, J. Nguyen, D. Moos, K. Tagbor. 1997, Increasing waterflood reserves in the and Wilmington oil field through improved reservoir characterization and reservoir management: Annual report submitted to the U.S. Department of Energy, Cooperative Agreement Number DE-FC22-95BC14934, unpaginated.

MacCallum, D., M. Pactel, and C. C. Phillips, 1998, Determination and application of formation anisotropy using multiple frequency, multiple spacing propagation resistivity tool from a horizontal well, onshore California, presented at the SPWLA 39th Annual Logging Symposium, May 1998.

Mayuga, M. N., 1970, Geology and development of California’s giant-Wilmington oil field, *in* Geology of giant petroleum fields-symposium: AAPG Memoir 14, p. 158-184.

Meyer, W. H., T. Maher, and P. J. McLean, 1996, New Methods Improve Interpretation of Propagation Resistivity Data, *presented at the 37th SPWLA Logging Symposium.*

Otott, G. E., Jr., 1996, History of advanced recovery technologies in the Wilmington field, *in* D. D. Clarke, G. E. Otott, Jr., and C. C. Phillips, Old oil fields and new life: a visit to the giants of the Los Angeles basin: Pacific Section AAPG, p. 37-44.

Otott, G. E., Jr., and D. D. Clarke, 1996, History of the Wilmington field: 1986-1996, *in* D. D. Clarke, G. E. Otott, Jr., and C. C. Phillips, Old oil fields and new life: a visit to the giants of the Los Angeles basin: Pacific Section AAPG, p. 17-22.

Otott, G. E., Jr., D. D. Clarke, T. A. Buikema, 1996, Long Beach Unit 3-D survey, *in* D. D. Clarke, G. E. Otott, Jr., and C. C. Phillips, Old oil fields and new life: a visit to the giants of the Los Angeles basin: Pacific Section AAPG, p. 51-55.

Phillips, C. C., 1996, Enhanced thermal recovery and reservoir characterization, *in* D. D. Clarke, G. E. Otott, Jr., and C. C.

Phillips, Old oil fields and new life: a visit to the giants of the Los Angeles basin: Pacific Section AAPG, p. 65-82.

Phillips, C. C., 1998, Geological Review of H; Sands, *in* U.S. Department of Energy, Increasing Waterflood Reserves in the Wilmington Oil Field Through Improved Reservoir Characterization and Reservoir Management: 1997 Annual Report, Contract No. DE-FC22-95BC7 4934, Appendix 1, 12 p.

Phillips, C. C., and D. D. Clarke, 1998, 3D modeling/visualization guides horizontal well program in Wilmington field, *in* Journal of Canadian Petroleum Technology.

Phillips, C. C., D. D. Clarke, and L. Y. An, 1996, Give new life to aging fields: Oil and Gas Investor, v. 39, no.9, p. 106-115.

Redin, T., 1991, Oil and gas production from submarine fans of the Los Angeles basin *in* K. T.Biddle, ed., Active Margin Basins: AAPG Memoir 52, p. 239-259.

Slatt, R. M., S. Phillips, J. M. Boak, and M. B. Lagoe, 1993, Scales of geologic heterogeneity of a deep water sand giant oil field, Long Beach Unit, Wilmington field, California, *in* Rhodes, E. G. and T. F. Moslow, eds., Frontiers in sedimentary geology, marine clastic reservoirs, examples and analogs: Springer-Verlag, New York, p. 263-292.

U.S. Department of Energy, 1999, Increasing heavy oil reserves in the Wilmington oil field through advanced reservoir characterization and thermal production technologies, partners: The City of Long Beach, Tidelands Oil Production Company (Tidelands), University of Southern California and David K. Davies and Associates, 1996 Annual Report, Contract No. DE-FC22-95BC1 493, 85 P.

Wright, T. L., 1991, Structural geology and tectonic evolution of the Los Angeles Basin, California, in K. T. Biddle, ed., Active margin basins: AAPG Memoir 52, p.35-134.